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SOUTHWEST GAS CORPORATION

ORIGINAL

August 29, 2008

Docket Control Office
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007-2996

Subject: <u>Docket Nos. E-00000J-08-0314 and G-00000C-08-0314</u>

Southwest Gas Corporation (Southwest) herewith submits for filing an original and fifteen (15) copies of its comments and responses to the questions listed by the Arizona Corporation Commission Staff in its letter to the docket, dated August 1, 2008.

Respectfully submitted,

Debra S. Gallo By [initials]

Debra S. Gallo, Director
Government & State Regulatory Affairs

Arizona Corporation Commission
DOCKETED

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE ARIZONA CORPORATION COMMISSION'S INVESTIGATION OF REGULATORY AND RATE INCENTIVES FOR GAS AND ELECTRIC UTILITIES	)))))	E-00000J-08-0314 & G-00000C-08-0314

Introduction

Southwest Gas Corporation (Southwest or Company) hereby respectfully submits its responses to the Arizona Corporation Commission's (ACC or Commission) Utilities Division Staff (Staff) questions defining the scope of the investigation into regulatory and rate incentives for gas and electric utilities. Southwest's responses to Staff's questions are largely driven by its experiences with regulation in Arizona, and its position in the state as the largest natural gas local distribution company. Southwest appreciates the opportunity to provide comments on the use of regulatory and rate incentives for gas and electric utilities and looks forward to a robust and informative discussion of the various issues. Listed below are Staff's questions and Southwest's responses.

Questions & Responses

What basic incentives and disincentives does today's regulatory structure (e.g., rate-of-return regulatory structure, adjustment clauses, test year determination, depreciation policies) provide to Arizona electric and gas utilities?

The proper evaluation of incentives and disincentives affecting Arizona's utilities must begin with the understanding that utilities are guided by the need to provide high quality, fair and reasonably priced service to customers while correspondingly attempting to achieve a competitive, risk-adjusted rate of return to compensate investors and attract necessary capital. Further, these goals are, in fact, complimentary, and must be thought of as such if the goal is to improve the timeliness and fairness of regulation in Arizona. Fiduciary responsibility to investors ensures that management has a constant incentive to provide utility service as efficiently as possible, while the need to retain and attract new customers ensures that management cannot sacrifice service quality to achieve short-term benefits for investors. These built-in checks and balances, along with well-guided regulation, can ensure high quality and reliable service at the lowest reasonable cost.

Today's regulatory structure provides a great deal of incentive for Southwest to operate as efficiently as possible. Rates are established based on historical test year costs and consumption. However, rates based on historical costs are typically dated by one to two years (regulatory lag) before rates become effective. Thus, management is typically forced to play catch-up because many costs will increase, and consumption may decrease from test year levels before rates even become effective. In Southwest's case, average use per customer has decreased by over 40 percent in the last 20 years. Therefore, the only effective way to stem financial deterioration between rate cases is to operate as efficiently as possible.

The current rate-of-return regulatory structure provides some incentive for Southwest to properly manage its investment to serve new customer growth. Because of regulatory lag, Southwest cannot afford to invest too much to serve new customers. High capital costs between rate cases negatively impact Southwest's earnings. However, the rate-of-return regulatory structure provides incentives for Southwest to make economically efficient investments to serve new customers as the costs will be reviewed as part of the rate base proposed in a future general rate proceeding.

Unfortunately, however, the current regulatory structure in Arizona fails to equitably address Southwest's declining consumption per customer. Current regulation tends to reward utilities whose use per customer is increasing because those companies are able to earn additional revenue per customer between rate cases. Opportunities to earn additional revenue for utilities with increasing use per customer occurs because revenues are linked to consumption through the current commodity-based rate design. The additional revenue, in and of itself, is not necessarily bad because the additional income is available to offset increases in other operating expenses. Unfortunately, not all utilities enjoy increasing use per customer. When usage is declining, current regulation fails to provide affected utilities an adequate compensatory framework between rate cases. Thus, current regulation results in a strong incentive for utilities, particularly natural gas utilities whose incremental capacity costs are much lower than electric utilities, to increase sales or use per customer.

What are the alternatives to the Rate Base-Rate of Return model?

Alternatives could include forms of "performance-based ratemaking" or "PBR" mechanisms. PBR mechanisms typically allow utilities to adjust annual revenue requirements up or down based on pre-established parameters and may include sharing of gains and losses, or returns on equity ("ROE") greater or lesser than the authorized ROE, between customers and shareholders. PBR mechanisms are generally established in a general rate case, and make adjustments, or allocate any sharing, without the necessity of going through a subsequent general rate case. PBR mechanisms are designed to provide an incentive to utility management to operate the business effectively and grow earnings, while maintaining reliable customer service. They also reduce the magnitude and frequency of general rate cases. The revenue decoupling mechanisms Southwest proposed in its current Arizona general rate case are examples of alternative mechanisms that work within the framework of existing rate base-rate of return regulation. These mechanisms would also allow adjustments outside of general rate cases and provide incentives, or at least remove the disincentive, for the utility to aggressively promote energy efficiency and conservation. Another alternative approach that could work within the current regulatory framework is the use of a fully projected or future test year to set rates rather than an historic test year. A projected or future test year would reduce regulatory lag and more accurately set rates based on costs expected during the period when rates will be in effect.

How do adjustment clauses affect utility incentives?

Adjustment clauses generally have a positive affect on utility incentives. To understand this concept, consider the effect on utility incentives of eliminating fuel adjustment clauses. Without a fuel adjustment clause, a company's incentive would be to minimize purchased fuel expenses at the potential cost of reliability. With an adjustment clause, the company is able to develop a more reliable portfolio knowing that if it does so prudently, it will be able to fully recover its costs. Adjustment clauses do not diminish a utility's incentive to operate efficiently because there are always risks of after-the-fact prudence reviews and/or adverse affects on utility earnings if costs are not effectively controlled.

Are incentives an appropriate tool to use in the context of fuel/gas procurement activities?

The limited use of incentives may be appropriate for fuel/gas procurement activities. However, incentive mechanisms must first be tailored to fit the unique circumstances of a particular utility. There are too many unique circumstances among different utilities to design a one-size-fits-all incentive program. While general policy statements may be applicable to all utilities, it would not be practical, nor likely, that a single set of detailed fuel or gas procurement incentive guidelines and policies could be developed that would be both applicable to all Arizona energy utilities and best serve the interests of Arizona's utility customers.

From Southwest's experience in another jurisdiction, where a gas procurement incentive mechanism is utilized, such incentive mechanisms provide a reward (or penalty) based on the actual incurred gas costs compared to a benchmark. Thus, the next step in developing a fuel or gas procurement incentive mechanism would be to identify the appropriate benchmark or benchmarks to which a utility's actual costs could be compared. Such benchmarks likely exist for a portion of the utility's fuel or gas purchases (i.e., certain gas commodity costs could be compared to published index prices for daily or first-of-the-month gas supplies), but do not exist for others (i.e., fixed interstate transportation charges incurred to ensure reliability, or financial hedging program costs). Consequently, any fuel or gas procurement incentive mechanism will only function for those portions of a utility's portfolio for which an appropriate benchmark exists. The remaining portions of the portfolio, for which there is no appropriate benchmark, should not be the subject of incentives.

Southwest agrees that some form of incentive may be appropriate for fuel or gas procurement activities. However, implementation should not be on a statewide basis. Implementation should be on a utility-by-utility basis, so the appropriate benchmarks and comparisons can be used to address each utility's individual fuel or gas procurement circumstances.

Can the regulatory incentive structure be changed to align a utility's financial incentives with energy efficiency investment?

Yes. As discussed above, under the current regulatory structure, there is a strong incentive to increase sales. The Secretary of Energy (Secretary Bodman) provided some insight at the 2007 NARUC summer meeting:

> It is quite obvious that our current utility ratemaking structure provides incentive for investor-owned utilities to sell more electricity and gas, not less. Encouraging efficiency by definition means selling less, which is counter-intuitive to the present business paradigm. So the recommendation to realign incentives is fundamentally crucial to making significant progress in the area of energy efficiency.
>
> We need to begin thinking about utility customers --- our citizens --- and what they are purchasing a bit differently: what customers are really buying is service, rather than the actual product: electricity or gas. Thinking in these terms makes it easier to conceive of energy efficiency as an enhanced service. Fortunately, some states already have experience on how to do this that we can all gain from.[1]

[1] http://www.energy.gov/news/5237.htm

Secretary Bodman further explained that some states provide financial incentives for delivering energy efficiency and other states use decoupling or some other form of removing financial disincentives. Clearly, the current system of rate-of-return regulation in Arizona needs to be changed to support the nation's goal of increased energy efficiency A number of ways exist to better align a utility's financial incentive with investment in energy efficiency or conservation. The primary method is to decouple a utility's sales of the commodity from its revenue requirement. A decoupling mechanism would, at a minimum, remove the financial disincentive for a utility to aggressively encourage and assist its customers in conserving energy and lowering their utility bills. Another method is to re-design rates to place most, if not all, of the recovery of a utility's fixed costs in a non-bypassable, periodic (monthly) fixed charge. This rate design would more closely align the utility's actual cost of serving customers with the recovery of its prudently incurred costs. It would also provide a more economically efficient price signal to customers, and reduce the volatility in customers' bills.

A September 2007 paper from the National Regulatory Research Institute or NRRI entitled *"Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas"* explores the relationship between regulatory bodies and the utilities they regulate. The paper describes a systematic approach to ratemaking that would result in more transparent, effective, and consistent decisions by regulators. In this paper, the NRRI looked specifically at gas utilities' incentives and disincentives for promoting energy efficiency under the traditional regulatory paradigm (and rate design). It also assessed new ratemaking practices and policies that may enhance the utility's incentive to undertake more or greater energy efficiency programs. A copy of the paper is attached as Appendix A for the convenience of the parties to this proceeding.

Can the incentive structure be modified to heighten the utility's incentives for management efficiency?

Utility management already has a variety of incentives to operate efficiently: (1) the threat of after-the-fact prudence reviews; (2) the need to provide adequate compensation to utility investors; and (3) for many companies, a significant component of management's compensation depends upon the utility's financial performance. Management must achieve sound financial results while providing safe and reliable service to customers. The current structure could, however, be modified to establish a risk/reward or sharing system. Such a system could reward a utility for successfully achieving target objectives. Utilities, and other companies, have attempted to foster and encourage management efficiency by establishing "at-risk" compensation programs. These programs reward managers for achieving or exceeding objectives, while withholding a portion of their compensation if objectives are not met.

The Commission, however, appears to frown on the use of management incentive programs as it has consistently disallowed recovery of all or a portion of management incentive compensation provided by utilities. If the Commission truly wants to encourage an incentive structure that promotes management efficiency, a basic first-step toward that goal would be to allow full recovery of utility "at-risk" compensation that supports this objective. This step would send a clear and strong signal to utility management to achieve even further efficiency gains.

Can incentives play a role in Arizona efficiently meeting its future utility infrastructure needs?

Yes. The importance of developing incentives and alternative funding mechanisms for future utility infrastructure was emphasized in a recent study prepared by Arizona State University[2] (a copy of the study is attached as Appendix B). For the period 2008 to 2032, the projected change in Arizona's population is an increase of 4.2 million people, which represents a 65 percent increase. Given the capital intensive nature of the utility industry, the projected growth in population will require a significant investment in infrastructure. The estimated total capital investment required in energy infrastructure to meet this population growth is between $74 billion and $86.5 billion. Under the status quo regulatory paradigm, the study warns of the possibility that Arizona may experience a funding gap:

> Arizona is in the precarious position of having major utilities with poor bond ratings and, at the same time, a sluggish regulatory process that results in periodic (typically large) rate changes rather than smooth rate ones. When market investors doubt the ability of a utility to recover costs in a timely fashion, ratepayers must absorb higher interest costs for the utility's debt financing.[3]

The study lists several alternative mechanisms that might be used to ensure adequate funding of utility infrastructure needs.

The Commission has already taken steps in its Policy Statement Regarding New Natural Gas Pipeline and Storage Costs (dated December 18, 2003) that provide gas utilities with incentives to efficiently meet future infrastructure needs. The policy encourages gas utilities to file applications, including requests for alternative cost treatment, for critical natural gas infrastructure projects. As a result of this policy, the

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[2] Infrastructure Needs and Funding Alternatives for Arizona: 2008-2032, Water Energy, Communications and Transportation, Arizona Investor Council, Executive Summary, May 2008, prepared by L.William Seidman Research Institute, W.P. Carey School of Business, Arizona State University.
[3] Ibid., p. 6.

Commission can consider requests for cost recovery proposals that are appropriate under the circumstances. The Commission used its policy in conjunction with the Transwestern Phoenix Lateral Project. Southwest, and other Arizona utilities, received pre-approval of specific prudent costs associated with the natural gas infrastructure for the Transwestern Phoenix Lateral. This process provides utilities with an incentive to participate in open seasons for desirable natural gas infrastructure projects because the precedent agreements that most purveyors of new infrastructure projects utilize are consistent with a utility's simultaneous pursuit of Commission pre-approval. For example, a utility's risk is reduced because precedent agreements include a "regulatory out" provision should the Commission not approve the utility's participation in a project. Southwest believes that the Commission's pre-approval process, and other potential incentives (e.g., up-front cost recovery or a "bonus" return on certain critical infrastructure projects) will play an important role in helping Arizona efficiently meeting its future gas supply demand and the infrastructure needed to provide that supply.

Furthermore, the Commission should identify administrative process changes for reviewing energy utility general rate cases that would provide utilities a more realistic opportunity to earn the Commission-authorized rates of return, thereby creating a climate that actually encourages, rather than discourages, investors to seek Arizona utility investment opportunities. Greater investment in Arizona energy utilities promotes more financially healthy utilities and provides those utilities the wherewithal to more efficiently fund Arizona's infrastructure needs.

Should the Commission consider "decoupling" mechanisms for electric and gas companies? If so, what type of decoupling?

Southwest is a strong proponent of decoupling. The Commission should definitely consider decoupling mechanisms for companies that are experiencing declining use per customer, which is the case for most natural gas companies. In Southwest's case, its residential use per customer has decreased by over 40 percent in the last 20 years. The current regulatory paradigm financially penalizes Southwest for this decrease, even though its customers have benefited in the form of reduced bills for natural gas service. The Commission should correct this problem by <u>at least</u> (additional financial incentive could also be provided, as noted earlier, aggressively encouraging reduced sales) positioning utilities to be financially indifferent to decreases in sales; thereby, allowing customers to benefit from lower energy costs without harming utilities' financial positions. Even where use per customer is increasing, the Commission must still consider decoupling in order to make the utility indifferent to undertaking measures to reduce its sales and achieve the attendant benefits of conservation of scarce energy resources and reductions in the customer's carbon footprint and greenhouse gas emissions. The type of decoupling mechanism should be tailored to fit each utility's specific situation and customer mix.

In the case of Southwest, where sales per customer have declined consistently for a number of years, simple revenue per customer decoupling, as Southwest has proposed, is appropriate because it allows customers to benefit from the reduced cost for natural gas service with no financial harm to the Company. This approach has been used in one form or another by approximately 26 utilities in 13 different states (excluding the five utilities in four states with straight-fixed variable designs). Decoupling also, as noted above, eliminates the financial disincentive to the utility to promote and encourage energy efficiency and conservation. Moreover, credit rating agencies view decoupling as a constructive step from a rating perspective. For example, Moody's Investor Services stated:

> LDCs (local distribution companies) that have, or soon expect to have, RD (revenue decoupling) stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in the face of adversity. This difference between those companies that have RD and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident.[4]

Can the regulatory incentive structure be altered to change the stakes for a utility making a build-or-buy decision or other infrastructure decisions?

Southwest interprets this question to primarily apply to an electric utility's decision as to whether to build a generating station or acquire purchased power from a third-party. A critical aspect of the build-or-buy decision process, at least from the Commission's perspective, must be consideration of how to most efficiently provide Arizona's utility customers' total energy requirements. Southwest suggests, and the data strongly indicates, that the use of natural gas appliances for end-use applications will reduce the peak demand for electric generation and/or the need to use natural gas in the electric generation process. This "total energy cycle" concept should be part of Arizona's planning process to keep total energy costs to customers as low as possible. Use of the "total energy cycle" will also reduce the overall carbon footprint and greenhouse gases that are emitted in Arizona.

[4] Moody's Special Comment, Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings, Moody's Investor Services, June, 2006, p.1 (See Appendix C).

What impact does the current regulatory structure regarding the build-or-buy scenario have on competitive bidding as a tool in resource selection?

As previously stated, Southwest considers the build-or-buy scenario applicable primarily to an electric utility's decision to build a generating station or acquire purchased power from a third-party. However, there are some parallels to a natural gas LDC. For example, to meet incremental load, Southwest has the option to 1) build a new pipeline to connect the new load with a supply basin; 2) buy incremental firm capacity from an interstate pipeline; or 3) buy firm gas supplies that are delivered to Southwest's city gate by a supplier with firm interstate capacity. The current regulatory structure appears to provide flexibility for a properly designed competitive bid for this type of resource selection.

Southwest could issue a request for bids to interstate pipelines and gas suppliers for service (either interstate capacity or bundled capacity and gas supplies) to meet incremental load. Any precedent agreement made to purchase such service could include a "regulatory out" provision. Southwest would compare those proposals with the option to build a new pipeline to connect new load with a supply basin(s), and select the preferred option. Southwest could then file an application for pre-approval of cost recovery or alternative cost treatment pursuant to the Commission's December 18, 2003 Policy Statement Regarding New Natural Gas Pipeline and Storage Costs. Should the Commission not approve the preferred option, Southwest would be able to walk away (generally without penalties) from the precedent agreement because of the "regulatory out" provision. While buying firm gas supplies delivered to Southwest's city gate may not have been contemplated under that policy, it is clear that both the option for Southwest to build a new pipeline and purchase firm interstate capacity requires additional infrastructure in Arizona. Therefore, the Commission could consider the option of buying firm gas at the city gate pursuant to that policy. However, because of the risk and substantial cost of constructing interstate pipelines, the playing field is significantly tilted towards the "buy" scenario for Southwest. Such risks and costs reinforce the importance of the Commission's December 18, 2003 Policy in assisting Arizona energy utilities in efficiently and effectively meeting their customers' future energy needs.

What are the best practices across the nation regarding regulatory incentives?

Southwest has experienced or observed what it believes to be two practices that it considers particularly deserving of a "best practices" designation: 1) the decoupling of revenues from sales to provide proper incentives to both customers and utilities in terms of energy efficiency and conservation; and 2) the use of a future test year to set rates, thereby reducing regulatory lag and ensuring customers are paying rates based on costs that will be incurred in the rate-effective period.

Are there any other specific topics that should be covered in the inquiry?

In the process of examining current and potential regulatory incentive mechanisms, the Commission should be cognizant of climate change legislation proposals and the ramifications to utilities and consumers. Southwest believes it is inevitable that some level or form of climate change program (federal, regional, or state) will be implemented affecting its Arizona operations.

In 2007, Arizona entered into a regional partnership as a member of the Western Climate Initiative (WCI), which is a partnership of seven states to address climate change and to establish greenhouse gas reduction targets. The WCI is expected to announce details this fall for a regional "cap and trade" market for emissions of greenhouse gases, which is slated to begin January 1, 2012. The Commission should understand the consequences on utilities and the ramifications for utility ratemaking from this proposal. For Southwest, a key ramification of this proposal will be an additional focus on energy efficiency and conservation programs in order to achieve greenhouse gas emission reduction targets.

In addition, Arizona Governor Janet Napolitano signed Executive Order 2005-02 establishing the Climate Change Advisory Group (CCAG) and directing the CCAG to, among other things, develop a climate change action plan. Page 50 of the climate change action plan discusses certain recommendations for energy savings goals for electricity and natural gas, and the implementation of the policy, program, and funding mechanisms that are needed to achieve these goals. One of the energy savings goals identified by CCAG for natural gas utility spending is to:

> ramp up to spending 1.5% of gas utility revenues on energy efficiency programs by 2015 pursuant to Arizona Corporation Commission (ACC) decoupling of gas sales and revenue. Further ***decisions by the ACC to decouple gas sales and revenues are viewed as central to achieving this target***. Emphasis added. Arizona Climate Change Action Plan, August 2006, p. 50.

Are there any legal impediments?

Southwest is not aware of any legal impediments to adopting regulatory or rate incentives or mechanisms for energy utilities.

RESPECTFULLY SUBMITTED this 29th day of August, 2008.

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APPENDIX - A

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Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas

The National Regulatory Research Institute

September 2007

Ken Costello.
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EXECUTIVE SUMMARY

The ratemaking process is complex and interactive, involving groups with different goals, interests and agenda. It also entails addressing a number of objectives, each of which has a distinct effect on the public interest. Different ratemaking options, which over the past few years gas utilities have proposed before their state commissions, also have varying propensities to advance those objectives, with the usual situation where one option would advance some objectives while impeding others. A systematic approach to ratemaking should result in more transparent, effective and consistent decisions. It can help to elevate the scientific aspect of ratemaking by combining objective and subjective information more formally. The public interest stands to benefit from this approach.

In reviewing different ratemaking proposals, state commissions should have access to unbiased information for helping them better understand and evaluate the consequences of a decision. To make an assessment of ratemaking proposals, commissions should follow three steps. First, commissions need to define the public interest by identifying the multiple objectives that comprise the public interest, assigning weights to those objectives and resolving the trade-offs among them. Second, commissions need to understand each ratemaking proposal fully in terms of how it advances or impedes the multiple objectives that comprise the public interest. Third, commissions need to use a logical, transparent decision-making process, such as multi-criteria decision analysis (MCDA), that selects or modifies ratemaking proposals that come closest to achieving the public interest, as defined by a commission. MCDA can improve regulatory decisions by making more explicit the relationship between different ratemaking mechanisms and the public interest. It allows a state commission to assess proposals systematically, based on both unbiased and subjective information. Under this approach, prior to a utility proposal, a commission would have enunciated its ratemaking principles and objectives in a public proceeding.

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I. Introduction

The purpose of this paper is to assist state commissions in assessing the public-interest effects of existing and new ratemaking methods.[1] The paper presents decision-making strategies that state commissions can apply to make this determination when encountering existing and new ratemaking methods proposed by utilities and other parties.

This paper uses a case study of recent ratemaking proposals by natural gas utilities. These utilities have requested their commissions to approve new ratemaking proposals, which in some instances represent significant departures from traditional practices. These new proposals challenge state commissions to make rational, systematic and transparent decisions in an environment where commissions must abide by standard legal requirements in setting rates in addition to accounting for policy-based objectives.

A major conclusion of this paper is that state commissions should articulate their objectives for ratemaking and place weights on those objectives. The merit of a ratemaking method depends upon how well it advances the totality of regulatory objectives compatible with the public interest. In the real world, the practice of ratemaking requires a commission to trade-off multiple objectives, some of which conflict. These objectives and their relative importance also change over time, warranting commissions periodically to revisit their longstanding ratemaking practices.

State commissions can apply different strategies to assess new ratemaking proposals. Decision-making involves choosing the best solution to a problem from among a number of options. A good decision-making process involves identification of the problem, developing and analyzing alternative options, choosing and implementing the best option, and evaluating the decision quality based on the results.

In reviewing different ratemaking proposals, state commissions should have access to unbiased information for helping them better understand and evaluate the consequences of a decision. To make an assessment of ratemaking proposals, commissions should follow three steps. First, commissions need to define the public interest by identifying the multiple objectives that comprise the public interest, assigning weights to those objectives and resolving the trade-offs among them. Second, commissions need to understand each ratemaking proposal fully in terms of how it advances or impedes the multiple objectives that comprise the public interest. Third, commissions need to use a logical, transparent

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[1] Ratemaking involves three distinct steps: (1) the determination of a utility's annual revenue requirements recoverable from customers, (2) the allocation of the total costs to each customer class or services, and (3) the creation of a rate design that will collect those costs.

decision-making process that selects or modifies ratemaking proposals that come closest to achieving the public interest, as defined by a commission.

Rate designs and cost allocations can produce results that conflict with market realities and underlying regulatory objectives. These consequences can undermine the societal benefits of regulation by producing outcomes that lie contrary to the public interest. Both regulators and public utilities recognize the negative outcomes from faulty ratemaking, although they disagree over the definition of "faulty." A public utility may perceive faulty ratemaking as the cause of revenue insufficiency and excessive risk allocation to company shareholders; regulators, on the other hand, may view faulty ratemaking as the cause of undue price discrimination, unfair risk shifting of certain costs to consumers, and loud complaints from consumers.

In their review of ratemaking proposals, state commissions should assume that regulatory objectives differ from utilities' objectives. If both public utilities and state commissions have the same objectives and rank them similarly, regulation would have a lesser role in setting rates, as the "invisible hand" of the marketplace could then be trusted more to guide a utility's actions toward the public good. But, almost always, utilities and commissions not only disagree over which objectives are relevant for ratemaking but also over the relative importance of each one.

II. The standard requirements for "just and reasonable" rates and policy-based objectives

A. Standard requirements

Most state commissions operate under the legislative and judicial mandates that they set "just and reasonable" rates for public utilities. These mandates reflect standard legal requirements imposed by court interpretations of statutes and of the Constitution. Although interpreted differently by regulators, just and reasonable rates typically have the following four features:

1. They reflect the costs of an efficient or prudent utility.

2. They reflect the cost of serving different customer classes and of providing different services and different levels of services.

3. They allow the efficient or prudent utility a reasonable opportunity to earn a return sufficient to attract new capital.

4. They avoid undue discrimination against any customer class (or customers within a class) or service (e.g., rates should not fall below short-run marginal cost).

The first standard requirement of "just and reasonable" rates prevents customers from paying for costs that the utility could have avoided with efficient or prudent management.[2] Regulators attempt to protect customers from excessive utility costs by scrutinizing a utility's costs in a rate case or by applying an incentive mechanism (with explicit rewards and penalties) that motivates a utility to act efficiently. Ratemaking practices can affect the propensity of a utility to act efficiently. Cost riders, where certain costs do not undergo a thorough review by the commission, may weaken a utility's incentive to control those costs, all else equal.

The second standard requirement, which involves a cost-of-service study, allocates costs to various customer classes and utility services.[3] The cardinal principle underlying cost allocation is that customers and services should bear those costs that they cause.[4] Although state commissions pay attention to cost-based principles, they often deviate from these principles in setting rates.[5] The reason for considering non-cost factors is that a commission has different public-policy and ratemaking objectives that cause it to depart from cost-based principles. A commission might feel that rates below fully allocated cost to low-

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[2] Axiomatically, the prudence test requires only reasonableness under the circumstances at the time that a utility made a decision or undertook an action; the test excludes consideration of later facts.

[3] A cost-of-service study can define cost as either embedded cost or marginal cost. Embedded cost represents a cost actually incurred by a utility, sometimes referred to as original cost, historical cost or accounting cost. Marginal cost is a forward-looking cost that accounts for the cost of a utility in providing an additional unit of service. See the Appendix for a more compete definition.

[4] This allocation results in the utility earning similar rates of return across customer classes and services.

[5] Many commissions consider cost-of-service studies as guides to setting rates, but not the only source of information or guidance. These studies incorporate judgment and apply imprecise data (e.g., load research). In addition, cost-of-service studies tend to equate rates of return across classes of customers, without accounting for differences in the risk to the utility of serving different customer groups. These studies may also conflict with other regulatory objectives and public policy goals.

income households, or subsidies to promote energy efficiency, are compatible with its goal to serve the public interest.

The third standard requirement permits the utility an opportunity to recover the costs (including its cost of debt and equity[6]) contained in the rates approved by the regulator in the last rate case. A regulator generally sets rates so that a utility has an opportunity to earn a fair or reasonable rate of return for shareholders, assuming efficient and economical management; but the regulator does not guarantee that return. A frequent area of contention in rate cases is the interpretation of "opportunity."[7]

The fourth standard requirement, while allowing some forms of price discrimination, prevents other forms (i.e., undue discrimination) where, for example, prices for some services are set below incremental costs or favorable price treatment to some customers pushes up rates to other customers. Price discrimination is more socially justified when it leads to a net increase in sales and increased welfare for consumers as a whole, but undesirable when most of the economic gains pass to the firm and total sales by the firm drop.[8] State commissions have authorized discriminatory pricing when it serves some public interest, such as economic development and the deterrence of uneconomic bypass.[9]

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[6] A utility's cost of equity corresponds to the more common term "normal profits." Both terms account for the cost a utility must incur to attract funds from shareholders. When shareholders invest in a utility, their normal return represents an opportunity cost since they forego earning normal returns in other firms by investing in the utility.

[7] A dictionary definition of opportunity relates to the term "good chance." The reader can see readily how different stakeholders can interpret this term to serve their own interest.

[8] The economics literature has shown that, where price discrimination increases total sales, it generally improves economic efficiency as well as the economic welfare of consumers as a whole. Otherwise, when total sales do not increase, the outcome is often higher profits for the selling firm but lower overall well-being for consumers. See, for example, W. K. Viscusi et al., *Economics of Regulation and Antitrust, 2nd edition* (Cambridge, MA: The MIT Press, 1995), Chapter 9.

[9] Historically, state commissions have approved a form of discriminatory pricing for some customers of gas utilities, namely, value of service pricing. Value of service pricing means pricing service to different customer groups based on the value each group places on the service. This pricing method is distinguished from "average pricing," in which customers of a particular grouping pay the same average price for a service regardless of the value it places on that

State commission-enabling statutes often direct commission to establish rates that are "just and reasonable." State commissions find this phrase difficult to interpret. Many views of "just and reasonable" exist. What is "just and reasonable" to one group, other groups may find otherwise. A common definition of "just and reasonable" relates to the setting of rates for different classes of customers and services based on the embedded cost-of-service (i.e., the costs incurred by a utility in serving different customer groups and in providing specific services).[10] A regulatory definition often applied is that all customers in a homogeneous class should pay the same rate.[11] "Just and reasonable" also typically entails no cross-subsidies in that no rate to any class of customer or service should result in negative earnings for the utility (i.e., rates that do not lie below a utility's short-run avoided or marginal cost, with negative earnings either absorbed by the utility's shareholders or compensated by other customers). "Just and reasonable" also applies to the opportunity for a utility to cover its prudent costs, including a rate of return, sufficient but no higher than necessary, to attract prospective investors.

B. Policy-based objectives

A review of state commission decisions in a large number of rate cases over time reveals at least eight policy-based objectives of ratemaking that commissions have exercised over time. These objectives reflect policy judgments made within the legal parameters established by statutory language and court decisions:

1. **"Public acceptability"** refers to how the consumers, the public and political actors will respond to the new rates resulting from a commission's decision. Commissions like to avoid negative public reaction to their decisions, as this places them in an unfavorable light and more likely would trigger

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service. In the mid-1980s several gas utilities turned to value of service pricing, which set rates below embedded costs but no lower than long-run marginal cost, to maintain industrial load that would have otherwise switched to oil. Most often, these rates were set at (or near) competitive prices for alternative fuels to protect utility ratepayers from the effects of "too deep" discounts.

[10] In a typical cost-of-service study, the goal is to allocate revenue responsibly such that utility would earn the same rate of return on the share of rate base allocated to each class of customer or service.

[11] The term "horizontal fairness" refers to the equal treatment of similar customers -- for example, customers imposing the same cost on a utility should face the same rate. Another notion of fairness, "vertical fairness," is the unequal treatment of dissimilar customers – for example, two customers imposing different cost on a utility should face different rates.

legislative intervention. Public acceptability should result in minimal customer complaints, legislative intervention and negative media publicity.

2. **"Rate stability and gradualism"** means that new rates and the methods used to determine them have some historical coherence. Especially troublesome are new rates that increase unexpectedly and are well above previously rates for particular classes of customers.

3. **"Equity or fairness"** is an elusive and contentious term that is the subject of heated debate in ratemaking proceedings. This term applies both to the regulatory treatment of different classes of customers, relative to each other, as well as to the treatment of utility shareholders relative to customers. This objective usually requires rates that are not "arbitrary or capricious," an allocation of business risk between a utility and its customers that matches risk with reward, and allocation of costs across customer classes based on cost-causation principles.

4. **"Affordable utility service"** means that almost all customers can afford utility service that satisfies essential energy and other needs. Meeting this requirement may require the utility to offer discounted rates to low-income households. For many low-income households, paying their utility bills under an unsubsidized rate may mean sacrificing the purchase of other commodities and services essential to their economic well-being. Funding of the subsidized rates would come from other customers.[12]

5. **"Efficient consumption"** means that consumers face prices for utility service that reflect cost of service, thereby inducing consumers to act efficiently. Below-cost prices result in wasteful use of utility service, while above-cost prices result in too little usage.[13]

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[12] Whether state commissions and utilities should concern themselves with the unaffordability of utility service to low-income customers is an issue that has permeated public utility regulation for decades. Many public policy analysts have argued that the real problem is certain households having inadequate incomes to pay for their essential goods and services. (This problem worsens for low-income households consuming energy, since they generally have low energy-efficient appliances and poorly insulated homes.) They contend that state and federal legislatures, or other governmental entities, should address this social ill by supplementing the income of poor households and by offering them financial support for energy-efficiency improvements, which would be more effective and efficient than subsidizing the prices they pay for utility service.

[13] This "efficient consumption" objective does not necessarily coincide with the objective of promoting what is commonly called "energy efficiency." Energy efficiency measures the ratio of energy input (e.g., therms of natural gas) and output (e.g., comfort). This term differs from the concept of economic efficiency, which accounts for both physical inputs and outputs and their societal value, usually expressed in dollars. Promoting energy efficiency per se may

6. **"Efficient competition"** refers to the utility and its competitors (e.g., retail marketers) having equal opportunities to compete for customers. Pricing of utility services plays a crucial role in determining whether this condition holds. When a commission fixes the prices of the local utility at embedded cost, for example, retail marketers can attract customers of the utility even when they are less efficient, because they have more pricing flexibility than the local utility. Efficient competition usually results in no uneconomic bypass and favoritism toward a utility affiliate.

7. **"Moderate regulatory burden"** refers to the objective of a commission to avoid frequent future rate cases. Rate cases absorb significant commission staff resources and time, diverting those resources from other commission activities.

8. **"Promotion of specified social goals"** means that a commission might want to pursue objectives that lie outside the normal mainstream of regulation. A commission might feel strongly about promoting energy efficiency in an environment of high gas prices, or about the increased unaffordability of gas service to low-income households. In achieving these objectives, a commission would approve special rates that deviate from traditional ratemaking principles (e.g., economic development rates that lie below embedded cost but above long-run marginal cost.)

The relative weights placed on different ratemaking objectives vary across state commissions, and shift over time in response to economic and political forces. During the 1980s and early 1990s, bypass of large customers from the local gas distribution system – i.e., customers buying a gas service directly from pipelines or installing their own spur line connected to the main pipeline, thereby

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lower economic efficiency in that the benefits of increasing energy efficiency may fall short of the additional costs.

Economic efficiency takes into account: (1) the cost to society from satisfying the demands of utility consumers (i.e., productive efficiency) and (2) the value that consumers place on utility service (i.e., allocative efficiency). The keys to achieving economic efficiency are to set rates based on marginal cost principles and to give utilities strong incentives to operate efficiently. Economic efficiency helps to avoid the waste of resources from both consumption and production. Economic efficiency involves maximizing total net economic value, while equity or fairness involves the distribution of net value among producers and consumers. Another way to look at the two concepts is that what matters to economic efficiency is maximizing the size of the pie, while equity or fairness cares about the slicing of the pie. Ratemaking involves treating these two concepts interdependently as maximizing the size of the pie requires efficient pricing to consumers, which therefore encompasses slicing the pie at the same time.

leaving the local utility unable to recover its fixed costs – was a major concern for both gas utilities and state commissions. The commissions responded by approving special discounted rates, even though they were discriminatory in nature, to avoid the revenue loss resulting if these customers bought their gas directly off the interstate pipeline.[14] Competition between natural gas and oil in the industrial sector during the early and mid 1980s placed pressure on state commissions to offer special (i.e., value of service) rates to large customers with fuel switching capability. Since the rise of natural gas prices in 2000, several commissions have paid more attention to energy efficiency by encouraging or requiring gas utilities to spend more money on, and engaging more actively in, promoting cost-effective energy conservation. This increased emphasis by regulators on energy efficiency has permeated the debate over proper rate design. As another recent issue, gas utilities have argued that traditional ratemaking has jeopardized their ability to earn sufficient revenues in view of the continuous decline in gas usage per customer.

III. Ratemaking methods and trade-offs among regulatory objectives

A. The standard two-part tariff

This section starts out by reviewing the salient features of traditional ratemaking for gas utilities. The discussion focuses only on the two-part base rate (i.e., the non-gas component of retail rates), which has received much scrutiny in recent years.[15, 16] The two-part tariff evolved during the early 20th century to

[14] These special rates were in response to the shortcomings of strict embedded-cost pricing in a competitive marketplace where consumers are able to switch providers and utilities lack absolute monopoly power. Many commissions approved special rates (with the condition that they at least cover marginal cost), fearing that if they did not, a utility's profits would fall and, ultimately, remaining customers would end up with higher rates, because a departing customer would no longer be contributing to the utility's fixed costs.

[15] Since 2000, the non-gas component of retail prices has declined proportionately because of the rise in wholesale gas prices. For many gas utilities, the non-gas component represents about 20-30 percent of the retail price.

[16] For all states (except for Hawaii), the utility recovers its purchased gas costs through some automatic adjustment mechanism. In most states, the utility passes through dollar-for-dollar purchased gas costs subject to a prudence review. The ex post facto review typically applies a rebuttable-presumption-of-prudence standard whereby parties contesting prudence must provide evidence of unreasonable conduct by the utility at the time of gas purchasing without the benefit of hindsight. A number of gas utilities have a cost-sharing incentive

replace the one-part tariff where the gas utility recovered all of its costs in a volumetric charge. Gas utilities and state commissions supported the two-part tariff as a way to increase consumption, reduce average cost, and generate sufficient revenues to recover fixed costs.[17]

1. Description of the standard two-part tariff

Traditional gas rates must recover the cost of gas sold plus the cost of building, maintaining and operating the gas utility system. In this discussion, we will set aside the portion of rates related to the cost of gas sold, and focus on the remaining costs. These remaining costs comprise what is normally called the "base rate." This base rate, in traditional ratemaking, is charged by means of a two-part tariff. The following arithmetical expression shows the standard two-part tariff for base rates set by gas utilities:

$$B_i = C + p \cdot q_i,$$

where the base rate for customer i (B_i, reflecting all non-gas costs) equals the sum of two components: the customer charge (C) applicable to all customers, and the volumetric distribution charge (p) times the quantity of gas consumed by customer i (q_i).[18]

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mechanism that allows a utility to profit from exceptional gas-procurement performance and to absorb some of the costs from sub-par performance. (See K. Costello and J.F. Wilson, *A Hard Look at Incentive Mechanisms for Gas Procurement*, NRRI 06-15, November 2006.) Some state commissions recently have reviewed the existing automatic adjustment mechanisms in response to volatile wholesale gas prices. Commissions have tended to adjust rates more frequently, in some instances going from an annual or semi-annual adjustment to a quarterly or monthly adjustment. Reasons for this change include reducing the financial burden on the utility and avoiding a large sudden increase in prices to consumers, both of which stemmed from high and volatile natural gas prices.

[17] The old one-part tariff structure had several problems. It resulted in (1) revenue instability for the utility, (2) poor (economically inefficient) price signals for customers, (3) failure to reflect higher cost to the utility for serving lower-usage customers, and (4) unfairness to high usage customers relative to low usage customers. Notwithstanding these negative outcomes, this rate design was an improvement over its predecessor, the unmetered fixed monthly bill (e.g., a customer pays $50 per month so matter how much gas she uses).

[18] The formula above assumes a uniform volumetric distribution charge regardless of the volume consumed. Many gas utilities have block pricing where the volumetric distribution charge varies between blocks of consumption. One common rate design is the declining-block structure, which in recent years has fallen out of favor because it encourages additional gas consumption. Declining-

The base rate recovers those costs related to investment in, and operation of, a gas transmission and distribution system. The customer charge typically includes the direct cost of serving a customer, including the cost for meters, meter reading, billing and collection, servicing an account, call centers and other costs independent of gas usage.[19] The volumetric transmission and distribution charge recovers the remaining non-gas costs of a utility. It includes both operating costs and capital costs not recovered in the customer charge.[20]

Using a numerical example, assume that the monthly customer charge is $10, the volumetric distribution charge is $1.50 per thousand cubic feet (Mcf) and monthly usage is 10 Mcf. Under this tariff structure, the customer's bill (excluding purchased gas cost) would be $10 + ($1.50·10), or $25. If the customer did not consume any gas during the month, she would be charged $10. The marginal price to the customer, i.e., the cost to the customer of consuming one additional Mcf of local distribution service, would be $1.50. Under prevailing rate structures, the marginal price exceeds the marginal cost to the utility, since the marginal price includes fixed costs. A secondary outcome is that the average price of gas to the customer (i.e., the customer's bill divided by monthly usage) decreases as the customer consumes more gas. In the example, the average price to a customer using 10 Mcf would be $2.50 per Mcf, while the average price at a usage level of 15 Mcf would be $2.17 per Mcf. This decline in average price reflects the decrease in a utility's average costs as monthly consumption increases, because the fixed costs of the system (to the extent they are recovered through the non-varying customer charge) are divided by more units of sale.

2. Consequences of the two-part tariff

Gas utilities using the two-part rate structure recover much, if not most, of their fixed costs in the volumetric charge, which not only makes the rate structure economically inefficient but also incompatible with some of the other regulatory

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block rates, however, have the benefits of providing a utility with earnings stability (by allowing it to recover its fixed costs in the lower-usage blocks) and of promoting economic efficiency when it sets tail-blocks charges at or close to marginal cost. (Economic efficiency requires only that the pricing of the unit of service consumed at the margin corresponds to marginal cost – not that all units of service do.)

[19] The monthly customer charge equals the allocated annual customer costs divided by the number of customer months.

[20] The volumetric distribution charge equals the distribution costs (minus the costs recovered in the customer charge) divided by the annual sales as determined at the last rate case.

objectives. One reason for this practice is that regulators as a rule disfavor high monthly customer charges, which would result from reallocating fixed costs from the volumetric charge to the customer charge. For many gas utilities, over 90 percent of their non-gas costs reflect fixed costs, with the majority of those costs typically recovered in the volumetric charge. As discussed next, problems arising from this allocation include under-recovery (or over-recovery) of a utility's prudent fixed costs and disincentives for a utility to promote energy efficiency.

The standard two-part tariff, as currently applied by most gas utilities, has several consequences. First, the recovery of some of the utility's fixed costs – other than the fixed costs recovered through the customer charge – depends upon the level of gas usage. When usage falls (or rises), because of factors such as abnormal weather, the business cycle, changes in customer behavior, and appliance and building characteristics, a utility's earnings also fall (or rise) because the utility must pay the fixed costs regardless of the revenue level. Where recovery of a large percentage of the fixed costs depends upon usage, a small change in usage can have a large effect on earnings. One consequence of linking fixed-cost recovery to usage is that the utility becomes riskier in the eyes of prospective investors and its cost of capital increases.

Second, because earnings fall with lower usage, the utility has a disincentive to promote energy conservation. If the volumetric charge includes only variable cost, then a drop in sales reduces costs and revenues proportionately, with no effect on earnings. This outcome would reduce any utility disincentive, at least between rate cases, to promote energy conservation.

Third, high usage customers bear a disproportionately higher share of fixed costs than low usage customers, even though much of these costs are more customer-related than usage-related. Examples of such costs, i.e., fixed costs recovered through the volumetric rate rather than through the customer charge, include the capital costs for distribution mains. Recovery of fixed costs also occurs lopsidedly during the winter or peak season when consumption is highest, which aggravates the problem of customers having high winter gas bills.

Fourth, the gas utility finds it more difficult to compete with alternative energy providers for large customers (e.g., oil retailers selling to industrial customers) because of the relatively high marginal price for gas delivery service. For high usage customers, a lower marginal price would reduce their total gas bills relative to a rate structure that allocates more of a utility's fixed costs to the volumetric charge.

Fifth, because the volumetric distribution charge includes fixed costs, the tariff is economically inefficient. Customers would tend to under-use gas since the marginal price includes fixed costs.[21] Ideally, from an economic-efficiency perspective, at the margin customers would pay a usage price equal to marginal cost.

Last, the incremental change in a customer's gas bill from increased usage (for example, because of cold weather) would be greater than if the usage charge excluded all fixed costs. This outcome would tend to cause gas bills to fluctuate more, especially for residential customers during the winter months.

B. New proposed ratemaking practices

1. Motivations

As of early March 2007, thirty-one investor owned gas utilities had rate cases pending before state public utility commissions. In 2006, state commissions decided rate cases for twenty-four gas utilities. These utility proposals encompass both the cost recovery and rate-design aspects of rate setting. Many of these proposals involve new practices reflecting changes in market conditions for natural gas as well as in regulatory and energy policies.[22] The major changes include:

1. The recent shift in policy by many state public utility commissions to encourage gas utilities to promote energy efficiency

2. Increased risk to gas utilities from higher gas prices causing a proliferation of bad debt expenses while simultaneously decreasing demand

3. Additional capital requirements caused in part by new safety regulations and the need to replace aging distribution mains (e.g., cast iron steel pipes)

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[21] Some readers might argue that although the price signal *per se* would cause customers to under-consume, non-price factors (e.g., information and capital-market barriers, externalities) would lead to customers under-spend on energy conservation. The poor price signal provided by the standard tariff, according to this view, would therefore counteract those barriers and represent a second-best solution. A preferred solution would be to address directly the non-price factors impeding economically efficient energy conservation.

[22] In recent years, electric and water utilities have also filed new rate designs and cost-recovery mechanisms, partially because of rising prices and an increased emphasis on reducing electricity and water usage.

4. Shifting regulatory priorities on the underlying objectives of ratemaking, including the need to assist low-income households and mitigate against high gas-bill volatility

The recent ratemaking proposals reflect the view of some gas utilities and other stakeholders that existing ratemaking practices, especially the longstanding reliance on the two-part tariff discussed in Part III, warrant revisiting because of changed market conditions and public-policy goals.[23] The natural gas industry has undergone fundamental changes in just a few years. First, wholesale gas prices have become more volatile and difficult to predict, and have reached much higher levels than 1990 prices. Although almost all gas utilities have purchased gas adjustment mechanisms to shift to consumers the risks of these market dynamics, consumers have expressed a preference for price stability and have cut back on their gas usage. Recent evidence has shown that customer demand response to higher gas prices have intensified over the last two years.[24]

Second, regulators and energy policymakers have intensified their efforts to promote energy efficiency, with gas utilities expected to play a more active role. Several state commissions have committed to implementing the National Action Plan for Energy Efficiency (www.epa.gov/solar/actionplan/report.htm), which affects both electric and gas utilities. A key recommendation of the Plan emphasizes the importance of ratemaking in aligning utility incentive with energy efficiency. Other state commissions have initiated proceedings to determine whether, and how, gas utilities should become more active in promoting energy conservation.

Third, high gas prices have aggravated the affordability problem for low-income households. Low-income households spend a much higher percentage of their incomes on natural gas than other households do. Partially because of the increased unaffordability of gas service to poor households, more customers have become delinquent in paying their gas bills, resulting in lost revenues to utilities that they did not anticipate at the time of the last rate case.

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[23] Over the past decade, both regulated and unregulated industries have undergone radical shifts in pricing practices. Internet service and telecommunications service are prime examples of this phenomenon. Numerous other examples exist for a wide range of industries where changes in market dynamics have led to new pricing practices.

[24] Some gas utilities have reported a sharper decline in gas usage per customer (normalized for weather) over the past two years than in the previous 20-25 years. One study concluded that non-price factors like new building codes and appliance efficiency standards have contributed to the downward trend of gas usage per customer over the past several years. (See Frederick Joutz and Robert P. Trost, *An Economic Analysis of Consumer Response to Natural Gas Prices*, prepared for the American Gas Association, March 2007.)

Fourth, because of high gas price volatility, hedging has become more important. Hedging activities by a utility in both its gas purchasing and ratemaking practices can help to stabilize customers' gas bills.

In sum, new ratemaking proposals stem mainly from the direct and indirect consequences of high natural gas prices since 2000. (See Table 1) Higher prices have increased risk to both utilities and their customers, calling into question the efficacy of prevailing ratemaking methods to promote the public interest in view of today's market and public policy environment.

Table 1: Consequences of High Natural Gas Prices

• Fewer households find natural gas affordable
• Energy conservation becomes more beneficial
• Fuel-switching becomes more imminent
• Price elasticity effect becomes more pronounced
• Bad-debt expenses increase
• Both the utility and its customer generally face more risk
• Hedging becomes more important from both the utility and customer perspective
• Utility customers become less satisfied with their utility service and regulatory oversight
• Overall, the gas industry becomes less stable with usage levels, gas bills and utility earnings more volatile and uncertain

2. New ratemaking proposals

A key issue in recent gas rate cases is whether the continuation of traditional ratemaking practices will allow a utility a reasonable opportunity to earn its authorized rate of return in light of the changes in the market environment and public policy, as discussed above. With several gas utilities arguing that traditional practices will not, they have proposed new cost and revenue riders in addition to new rate designs.

A list of new ratemaking proposals includes:[25]

- Rider for revenue deviations from some baseline level;[26] hereafter, this paper refers to this mechanism as a revenue decoupling (RD) rider[27]

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25 The Appendix describes some of these ratemaking mechanisms.

26 The generic term "revenue decoupling" refers to the separation of a utility's earnings from actual sales. Under this definition, revenue decoupling

- Straight fixed-variable (SFV) rate design, where the utility shifts all the fixed costs, both customer and demand related, out of the volumetric charge to a fixed charge such as the customer charge or demand charge

- Earnings sharing mechanism (or sometimes referred to as a return stabilization mechanism) where periodic adjustments, usually annually, occur when the utility's actual rate of return on equity falls outside some pre-determined band[28]

- Rider for bad debt[29]

- Rider for pipeline integrity management

- Rider for pipeline replacement costs

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includes riders, specific forms of declining-block rate structures, and a SFV rate design where the utility recovers all of its fixed costs in a non-usage charge.

27 Under RD riders, actual revenues correspond to the utility's revenue requirement, as determined in the last rate case, with rate adjustments made between rate cases as sales volumes deviate from the predetermined baseline level (e.g., weather-normalized usage per customer). In contrast, under traditional ratemaking, the utility's revenues change as sales volumes vary. With revenues more stable under a RD rider, the utility's actual earnings would deviate less from the level established during the last rate case. One misperception is that a RD rider would guarantee that a utility earns its authorized rate of return between rate cases. RD riders reconcile revenues, not costs. Unexpected cost increases (or decreases) and fewer (or more) new customers than expected would cause actual return on equity to deviate from the expected return. A RD rider, however, would increase the likelihood of a utility earning its authorized rate of return.

28 Gas utilities have argued, among other things, that earnings sharing would extend the time between general rates cases, better link rates to more current information on costs and sales, and keep the commission current on the financial condition of a utility.

29 Most of these riders involve recovering the gas cost portion of bad debt expense in the purchase gas adjustment (PGA) mechanism. Utilities proposing these riders have argued that their bad debt has increased significantly over the past few years because of the combination of high gas commodity prices and more customers falling further behind in paying their gas bills. They conclude that the practice of recovering bad debt as a fixed expense in base rates is no longer appropriate.

- Rider for pension costs

- Rider for energy efficiency or demand-side management costs

- PGA-like mechanism that tracks under and over recovery of a utility's fixed costs (i.e., fixed cost balancing accounts) with periodic fixed cost true-ups between rate cases

The new ratemaking proposals largely attempt to stabilize utility revenues and to allow recovery of certain costs outside a rate case review. They reflect the view that the longstanding use of a test year (i.e., a twelve-month period chosen to calculate the required revenue to recover a utility's distribution non-gas costs) to measure certain costs and gas sales for the rate-effective period is no longer appropriate. The basic argument made by proponents of new ratemaking methods is that events in the natural gas sector have made costs and sales difficult to predict and unstable. Even with modification to historical costs and sales for "known and measurable" changes, according to this argument, a gas utility would still face high risk, reducing its ability to earn its authorized rate of return.

The concern by gas utilities over revenue stabilization stems from what they see as the asymmetrical distribution of sales around some baseline or normalized level of sales. That is, they perceive the probability of actual sales falling below some baseline level set by a commission in a rate case to exceed the probability of actual sales exceeding the baseline level. A major argument for this view is that commissions generally determine base rates assuming no continuation of a decline in gas usage per customer. Gas utilities have argued that this assumption is contrary to statistically based predictions and past trends.[30]

Most of the new ratemaking proposals by gas utilities involve the use of trackers or riders to allow the utility to adjust its rates outside of a rate case.[31]

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[30] Gas utilities in several rate cases have shown a decline in usage per customer over the past two decades. Although parties to these proceedings generally have not disputed this phenomenon, some have questioned whether this decline will continue in the future. Reduced consumption per customer does not imply that utilities' total gas sales to residential customers will fall in the future. (See Energy Information Administration, *Annual Energy Outlook 2007*, February 2007 and other projections.) Most studies expect moderate growth in total residential sales over the next several years, even in view of a continued decline in sales per residential customer (with growth varying by state and region). These projections call for utilities' revenues from residential sales to grow between rate cases because of the addition of new customers offsetting a decline in use per customer.

[31] Trackers or riders refer to a mechanism that allows a utility to adjust its rates without having to file a formal rate review, although any resulting rate

For the past thirty years, state commissions have allowed utilities to recover changes in their purchased gas costs through a rider-type mechanism, commonly called a PGA mechanism. Some commissions have also permitted gas utilities to recover other costs, for example those related to energy efficiency activities, outside of a rate case.

Commissions generally frown upon pass-through of costs outside of a rate case (even when subject to a prudence review) unless extraordinary circumstances exist. Commission decisions have focused on whether to pass through costs, and make rate adjustments for unexpected changes in sales, outside of rate case review in light of the possible downside consequences.[32]

Historically, commissions apply a three-part test in judging the merits of a rider or tracker. The three-part requirement for commission approval of riders and trackers typically include: (1) the cost or sales activity must lie outside the control of the utility, (2) variations in outcomes can have a material effect on utility earnings, and (3) the activity is difficult to predict.

The reluctance of commissions to approve riders and trackers mainly lies with their effect on shifting risk to consumers and on diminishing regulatory lag. Regulatory lag refers to the time gap between when a utility undergoes a change in cost or sales levels, and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs. The reason is that when a utility incurs costs, the longer it has to wait to recover those costs, thus the lower its earnings become. Consequently, the utility would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important element in motivating utilities to act efficiently. Regulatory lag is a less than ideal method, however, for

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changes usually receive some level of regulatory oversight. These rate adjustments can occur because of the incurrence of special costs or the realization of sales departing from some predetermined baseline level. This mechanism is generally only applied under unusual circumstances. Some state commissions approving cost trackers place a cap on the amount recovered through the mechanism, with costs above the cap deferred for later recovery.

[32] Prior to the recent interest in revenue decoupling, rate adjustments for sales focused mostly on weather normalization adjustments (WNAs). The mechanism adjusts customers' monthly gas bills, usually during the winter heating season, to reflect weather patterns commensurate with "normal weather." The rationale for WNAs centers on the effect of the traditional ratemaking practice to cause earnings to fluctuate based on actual sales. Twenty-seven state commissions currently allow at least one gas utility to use a WNA mechanism. (See K. Rogers, "Revenue Decoupling: Trend or Transitions," presented at the Mid-Atlantic Conference of Regulatory Utilities Commissioners Annual Convention, June 5, 2007.)

rewarding an efficient, and penalizing an inefficient, utility. Some of the additional costs may fall outside the control of a utility (e.g., increase in the price of materials), and any cost declines may not relate to a more efficient utility (e.g., deflationary conditions in the general economy).

C. Trade-offs among objectives

1. Challenges for state commissions

The new ratemaking proposals advance some regulatory objectives while impeding others. The challenge for regulators is to weigh these objectives and measure (if possible) the effect of a ratemaking mechanism on each specified objective. Assigning weights requires judgment by the regulator, while examining the effects demands analytical skills supplemented by data and other unbiased information.

Table 2 shows how specific ratemaking practices (described in the Appendix) can have both positive and negative effects on different regulatory objectives. Stakeholders have proposed these practices before state commissions, who have either approved them or rejected them.[33] (The author used his best judgment, applying economic analysis and available empirical evidence, in determining the effects of each ratemaking practice on either advancing or hindering individual objectives. Some readers may rightly disagree with these assessments.)

[33] This paper discusses some of these ratemaking practices. In the Appendix to this paper, the reader can find a brief description of each ratemaking practice; other publications contain more detailed descriptions. (See, for example, NARUC Subcommittee on Gas, *Gas Distribution Rate Design Manual*, 1989; American Gas Association, *Gas Rate Fundamentals*, 4th Edition, 1987; and M. Harunuzzaman and S. Koundinya, *Cost Allocation and Rate Design for Unbundled Gas Services*, NRRI 00-08, May 2000, available at www.nrri.ohio-state.edu).

Table 2: Ratemaking Practice and Trade-offs Among Objectives

Ratemaking Practice	Objective(s) Advanced	Objective(s) Hindered
Standard Two-Part Tariff	Public acceptability, fairness in risk sharing	Efficient price-driven gas consumption, revenue and earnings stability, promotion of utility-initiated energy efficiency
Revenue-Decoupling Rider	Revenue and earnings stability, neutral utility incentives for the level of gas usage, fairness to the utility in recovering fixed costs	Fair allocation of business risk, public acceptability, efficient price-driven gas consumption
Straight Fixed-Variable Rate	Revenue and earnings stability, efficient price-driven consumption, neutral utility incentives for the level of gas usage, more equitable cost allocation	Equity to low usage customers (many of whom may be low-income), public acceptability; gradualism
Weather Normalization Adjustment	Revenue and earnings stability, winter gas-bill stability	Public acceptability
Inverted-Block Rate	Promotion of customer-initiated conservation, assistance to low-income households	Revenue and earnings stability, allocative efficiency; non-discrimination
Declining-Block Rate	Revenue and earnings stability, improved system utilization (i.e., productive efficiency)	Promotion of price-driven energy conservation, non-discrimination
Cost Rider	Earnings stability, fairness to the utility, fewer rate cases	Robust incentives for cost control (less regulatory lag), fair allocation of risk
Cost-Based Customer Charge	Allocative efficiency, more levelized gas bills across seasons	Public acceptability, equity to low usage customers (many of whom may be low-income)
Flexible Rate	Responsive to competitive and other conditions, improved system utilization (i.e., productive efficiency), avoidance of uneconomic bypass	Non-discrimination, fairness to captive customers
Special Contract	Responsive to competitive and other conditions, improved system utilization (i.e., productive efficiency), avoidance of uneconomic bypass	Non-discrimination, fairness to captive customers
Discriminatory Rate in General	Responsive to competitive and other conditions, improved system utilization (i.e., productive efficiency)	Fairness to captive customers
Rate Based on Marginal Cost Allocation	Price efficiency, improved system utilization (i.e., productive efficiency)	Preciseness of cost data, rate stability, public acceptability
Seasonal Rate	Allocative efficiency, equitable cost allocation across seasons	Affordability, public acceptability
Earnings Sharing	Earnings stability, fewer rate cases, allocative efficiency	Robust incentives for cost control (less regulatory lag)
Targeted Subsidized Rate	Affordability	Allocative efficiency, non-discrimination

The next section of this paper attempts to show alternative strategies (i.e., decision rules) that regulators can apply to assess and compare the public-interest aspects of different ratemaking practices. All of these strategies, in different ways, take into account the underlying objectives of ratemaking, with regard to both their specification and their relative importance. Looking at Table 2, a state commission would find it difficult to rank and compare the ratemaking practices in advancing the public interest without first knowing the relative importance of each objective in addition to the trade-offs involved.

2. Illustrations of trade-offs among regulatory objectives

Ratemaking decisions made by a commission typically have conflicting consequences. That is, the ratemaking method approved advances some particular regulatory objectives while impeding others. The classic example is marginal cost pricing. (Marginal cost pricing sets price equal to the cost to the utility of the last unit of service.[34]) This pricing rule promotes economic efficiency by providing consumers with proper price signals while, some argue, clashing with the objectives of equity and gradualism.

Another example of conflicting outcomes relates to seasonal pricing. (Under seasonal pricing, a gas utility would charge higher rates during the winter months when demand and marginal cost are the highest. For an electric utility, rates would typically be higher during the summer months.) This pricing method has the positive features of giving consumers better price signals, of resulting in a more efficient use of a distribution system's facilities, and of requiring no special meters. Yet, some stakeholders have opposed, and some state commissions have rejected, seasonal pricing, for both the electric and gas industries, because it would cause rates to be higher during periods of peak consumption. The higher utility bill during peak periods would likely meet with public scorn, which it has in some instances, and negative media coverage.

Another example is special contracts to a large industrial customer. These contracts have the attractive features of mitigating uneconomic bypass,[35] of

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[34] Most often, utilities apply marginal cost principles to allocate costs. Once a utility determines the relative marginal costs of serving various customer classes, for example, marginal costs are then scaled to the utility's total revenue requirements. Thus, the actual marginal cost would only equal the utility's cost of service by accident and would not constitute the determining factor in establishing the class revenue requirements used to set rates.

[35] Uneconomic bypass refers to the situation where a customer turns to a non-utility provider for one or more services when the alternative provider has higher total costs but lower prices. It is uneconomic because society incurs higher cost in meeting the demands of a customer. One major cause of uneconomic bypass is the inability of the local gas utility to lower its rates below fully allocated embedded costs, which under certain circumstances (e.g., a utility

responding to competition and of contributing to economic development. Yet, they do reflect discriminatory pricing, which conceivably could force other customers to "fund" these special contracts through higher rates, as these contracts result in the utility recovering less of its fixed costs from the industrial customer than what it recovered previously.[36] Other examples abound where a particular ratemaking practice advances some objectives while hindering others.

Especially in regard to a revenue-decoupling rider and SFV rate design, stakeholders recently have made arguments reflecting the relative importance of different regulatory objectives.[37] For a revenue-decoupling rider, the argument centers on whether circumstances warrant the use of a rider to protect the utility from the possibility of less-than-expected sales. Utilities have argued that in the absence of a rider, they will not have a reasonable opportunity to earn their authorized rate of return. Opponents of a rider have argued that a utility can offset revenue losses from declining usage per customer by adding new customers and improving its productivity.[38] Some opponents of a RD rider also have argued that the downward movement of gas usage per customer in the past does not necessarily constitute a trend that will continue in the future.

Another argument relating to revenue-decoupling riders revolves around the issues of what role, if any, a gas utility should play in promoting energy efficiency and the incentives the utility needs to undertake this activity.

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has a high level of surplus capacity) could far exceed its marginal cost. Another cause of uneconomic bypass is faulty rate design where certain customers within a grouping (e.g., high usage customers within the industrial class) pay more then the utility's cost of serving them and, thus, higher then competitive alternatives.

[36] Although the rates to other customers may be higher than before the special contract, they will be lower than what the rates would have been if the customer had actually bypassed the local utility, assuming the utility's unrecovered sunk costs are assigned to the remaining customers rather than to the utility's shareholders..

[37] See, for example, K. Costello, *Revenue Decoupling for Natural Gas Utilities*, NRRI 06-06, April 2006 (http://www.nrri.ohio-state.edu/nrri-pubs); and K. Costello, "Revenue Decoupling for Gas Utilities: Know Your Objectives," presented at the Mid-Atlantic Conference of Regulatory Utilities Commissioners Annual Convention, June 5, 2007.

[38] Opportunities to add new customers and improve productivity, of course, would vary from utility to utility. In the Southeast (where electricity rates are low relative to most other parts of the country), for example, gas utilities have seen residential customers switching to electric heat pumps. Thus, for these gas utilities at least, the prospects for adding new customers are dim.

Opponents of these riders have argued that the utility should not involve itself with energy efficiency activities or if it does, a revenue-decoupling rider is still not justifiable.

The issues surrounding SFV rate design are contentious as well. Sometimes proposed to state commissions as an alternative to a RD rider (in terms of its ability to separate earnings from sales), it has met with criticism by commissions and some stakeholders. As Table 3 shows, the reader might expect state commissions to prefer a SFV rate design to a RD rider in view of the dominance of SFV in advancing seemingly important regulatory objectives. Yet, while some commissions have recently approved a SFV rate design, in most states gas utilities have steered away from proposing SFV, knowing well if they did, strong opposition from various sources, including commission staff, would ensue. Instead, gas utilities have more commonly proposed RD riders, with the majority of those proposals approved by state commissions. As discussed in the next section, one possible explanation for this disparate acceptance of these outwardly similar ratemaking mechanisms lies with the high weight commissions assigned to the negative features of SFV. SFV would adversely affect low usage customers, for example, some of whom may consume little gas but under SFV could face a significantly higher monthly minimum charge.

Table 3: Comparison of SFV with RD Rider

Advantages of SFV over RD	Disadvantages of SFV over RD
More compatible with sound economic (e.g., marginal cost) principles	Adverse effect on low usage customers, many of whom may be low income
Increased competitiveness of the utility for high usage customers from lower volumetric charge	Reduced incentives for customer-initiated energy efficiency from a lower volumetric charge
Elimination of intra-class subsidies favoring low usage customers	Possible significant increase in summer gas bills
Simpler to implement and for customers to understand	Likely stronger opposition from the public, stakeholders, and commission staff
Common pricing method for capital-intensive services	
No periodic true-up or price changes between rate cases, with longer regulatory lag	
More stable gas bills during the winter months	
Evenly allocates the recovery of fixed costs across seasons	
Neutral utility incentives for promoting or reducing gas consumption	

One way to look at a SFV rate design, relative to standard ratemaking, is that those customers who consume below the average-use level would have higher bills. The perception held by many state commissions and stakeholders is that many of the low usage customers are also low-income households.[39] One can conclude from the general rejection of SFV rate design is that even though SFV compared with a RD rider would be more economically efficient, result in more stable and levelized gas bills across seasons, would not require periodic true-ups, and is simpler for customers to understand, state commissions find either its disadvantages more persuasive or do not understand its advantages.[40] State commissions apparently attach a high significance to continuing with a rate design favorable to low usage customers and to gain public acceptability. No other explanation comes to mind, although recently opponents of SFV have argued that this rate design discourages price-driven energy conservation. The reason for less price-driven energy conservation is the lowering of the price of gas consumption at the margin to include only the gas-cost component.

IV. Strategies for assessing ratemaking practices

Ratemaking requires consideration of statutes and legal rules, economic principles, precedent, the trade-offs among different regulatory objectives, including public acceptability. Regulators need to apply their judgment on (1) what objectives ratemaking should achieve, (2) the relative significance of each objective, and (3) the willingness to impede certain objectives to advance others (e.g., the loss of economic efficiency from rates deemed fairer).

Before applying this judgment, the regulator should begin by reviewing unbiased information and analyzing how each ratemaking option advances some objectives while hindering others.[41] (See Table 2, for examples.) Overall, good

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[39] Some analysts question this perception, as a higher percentage of low-income households reside in energy-inefficient homes than other households do, because of their financial constraints in purchasing energy-conservation hardware and services. Let us assume, however, that the evidence shows low-income households to consume, on average, smaller amounts of gas than other customers do. A commission can modify the SFV rate design to charge a lower monthly fixed charge to identified low-income households. Alternatively, the utility could offer a rebate to those customers. A rebate would change the form of the subsidy, not the fact of its existence.

[40] We also observe a number of industries with largely fixed costs pricing their services on a fixed basis. These services include DSL, Internet access, local phone, and cable and satellite TV.

[41] This information could come from commission staff testimony and other advisory documents that staff can draft for commissioners.

ratemaking requires judgment, and unbiased analysis and information to arrive at a decision that best serves the public interest. Judgment reflects the preference of a decision-maker for different objectives underlying ratemaking and the strategy it applies based on the available, though often incomplete, information. This section of the paper will discuss different strategies for organizing and interpreting the information presented to commissioners.

A. Problems with the current decision process for ratemaking

An optimal process for decision-making by state commissions involves ordering and interpreting the information presented to them in a way that best advances the public interest. This approach requires that commissions: (1) define the public interest in terms of the objectives they assign to ratemaking, (2) comprehend the effect of each ratemaking proposal on advancing and impeding the different objectives, and (3) apply a logical decision-making strategy to select or reject a ratemaking proposal.

The current process applied by state commissioners for deciding on ratemaking proposals tends to have several suboptimal features in common.[42] First, commissions often do not explicitly consider and define the criteria for assessing ratemaking options. Although commissioners take into account different objectives for ratemaking, they often do not express what those objectives are, how to measure them, and what effect they have on the public interest. Commissioners might express the need for "just and reasonable" rates but they do not typically say what criteria (e.g., the acceptable degree of price discrimination, the proper allocation of business risk between shareholders and consumers) would support such rates. "Just and reasonable" thus becomes a mantra, or a post-hoc justification, rather than a decision criterion whose effect on a decision can be traced.

Second, commissioners often choose ratemaking options based on implicit weights for individual objectives, without identifying those weights in the written opinions. These opinions oftentimes fail to articulate that they favor one ratemaking practice over another because certain objectives are more important than others in serving the public interest. The public thus remains uninformed about the real reasons for the decision.

Third, ratemaking decisions often forego comprehensive "grounds up" analysis in favor of focus on the marginal gains over the status quo or over other

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[42] Suboptimal decision-making results in an outcome that fails to maximize the public interest. Such an outcome can come from inadequate availability of objective information, the intent by the decision-maker to serve his own interests or special interests, and the lack of an analytical framework from which the decision-maker processes the information presented to them.

alternatives. Commissions typically make ratemaking decisions by reacting to the positions of stakeholders, who present conflicting information, in the absence of pre-existing commission statements enunciating ratemaking principles and weights assigned to different objectives. Taking a reactive stance makes commissioners vulnerable to the political influence of individual special interests by attempting to "balance" the positions of those interests (which may have varying degrees of effective representation in the rate case) in reaching a compromised decision. Often, trying to balance those positions does not advance the public interest.

Fourth, commissioners often make trade-offs among different objectives on an ad hoc basis. They do not explicitly analyze, for example, the trade-off between allowing a utility to recover certain costs through a rider and the incentive of the utility to control those costs. Another example is the trade-off between avoiding a dramatic change in rate design and the consequences of continuing with economically inefficient rates. Over time, policy becomes unpredictable, thus diminishing credibility.

Overall, the ratemaking process across the states frequently lacks clear regulatory guiding principles, priorities or guidelines creating a moving target for commissions, utilities and other stakeholders. Consequently, the regulatory process is less efficient and resource-draining than it could otherwise be.

B. Multi-criteria decision analysis

1. Conceptual issues

An approach generically known as multi-criteria decision analysis (MCDA) is well suited for ranking and comparing different ratemaking options based on evaluation criteria. This approach can help to align unbiased and analytical information with commissioners' judgment in a systematic manner, thus allowing for more rational, transparent and efficient decision-making.[43]

MCDA is especially useful for addressing problems of a multi-objective nature, where decision-makers have to make trade-offs among multiple objectives. MCDA can assist commissions in making these trade-offs by providing them with an orderly framework to assess the implications of different value judgments for decisions. By varying the weights or significance attached to utility-initiated energy efficiency activities, for example, a commission can

[43] As one analyst has stated, MCDA can "provide help and guidance to the decision-maker in discovering his or her most desired solution to the problem (in the sense of that course of action which best achieves the decision-maker's long-term goals." See T.J. Stewart, "A Critical Survey on the Status of Multiple Criteria Decision Making Theory and Practice," *OMEGA*, vol. 2, nos. 5-6 (1992): 569-86.

determine any change in the ranking of a revenue-decoupling rider relative to other ratemaking options. Another example is where MCDA can help to determine if an increased emphasis on price-induced energy conservation causes declining-block rates to fall below some threshold level for acceptance.

The application of MCDA to ratemaking requires several steps:

a. *Frame the decision problem:* Two key questions recently have confronted state commissions: (a) Does the traditional ratemaking method deny a gas utility the reasonable opportunity to earn its authorized rate of return? and (b) Does the traditional ratemaking method provide a gas utility with a weak incentive or disincentive to support energy efficiency? A related question is how a commission can promote the twin objectives of revenue sufficiency and energy efficiency with minimal negative effects on other objectives (e.g., the "fair" allocation of business risk, public acceptability).

b. *Define the objectives and the set of evaluation criteria:* MCDA uses criteria to operationalize the objectives for comparing and evaluating potential options. An objective indicates a direction toward improved outcomes; for example, a stronger incentive for a utility to promote energy efficiency, or a better opportunity for a utility to earn its authorized rate of return. A criterion or attribute measures an objective in a way useful for analysis; the expected number of customer complaints, for example, can indicate public acceptability, and the relationship of price to marginal cost can help to gauge the presence of efficient consumption.

c. *Specify the options:* What ratemaking practices should a commission review, for example, in addressing the problem of revenue sufficiency and other problems warranting further consideration?

d. *Develop a performance matrix:* Each row in the matrix describes an option and each column measures the performance of the option against each objective or criteria (the column entries represent, for example, how well each option promotes the objective of economic efficiency). The next subsection illustrates a performance matrix.

e. *Identify the preferences of decision makers:* This step comprises the normative aspect of MCDA, where the decision-maker designates preferences for the different objectives or criteria. The identification and measurement of preferences allows the decision-maker to assign weights. A decision-maker can express her preferences by ranking the criteria, by assigning numerical weights, by identifying criteria as "must haves" and others as "desirable but optional," or by verbal evaluations.

f. *Select a method that aggregates the information presented to decision-makers for ranking and comparing the different options:* This step allows for the comparison of two or more options with varying performance over the range of objectives or criteria. The method constitutes a decision rule or strategy for sorting and evaluating the information available to decision-makers.

g. *Interpret the results and apply sensitivity or robustness analyses:* Decision-makers should not solely rely on MCDA to reach decisions; this tool, however, should assist in providing support for any decision made. The robustness of a decision also depends on whether the selected option continues to rank the highest, for example, as the decision-maker assigns a set of different weights for the objectives or criteria.

2. Illustration of MCDA application

The relevant question facing several state commissions today is what gas ratemaking options best address the factors affecting the cost and risk of providing gas service. Previously, this paper identified the underlying arguments for a different ratemaking approach. First, under the traditional two-part tariff, a utility is more unlikely in the current market environment to earn its authorized rate of return than in the past when demand for gas was more robust and stable. This outcome results from the combination of the conditions that (1) a utility recovers most of its fixed costs in the volumetric charge, (2) declining gas usage per customer is likely to continue in the future, and (3) the base rates set in the last rate case assumes no future decline in gas usage per customer. Second, since the promotion of energy efficiency has emerged as a legitimate activity of gas utilities, the extant ratemaking approach conflicts with the efforts of utilities to reduce their sales.

Let us assume that a hypothetical commission has four ratemaking objectives:[44] (1) revenue sufficiency, (2) promotion of utility-initiated energy efficiency measures that reduce gas consumption, (3) economic efficiency and (4) public acceptability. The criteria or metrics used to measure these four objectives include the likelihood that a utility would earn its authorized rate of return, the effect of energy-efficiency activities on a utility's earnings, the relationship of price to marginal cost, and the number and intensity of consumer complaints.

Let us next assume for simplicity that the three ratemaking options under consideration include the existing method (i.e., the standard two-part tariff where the volumetric charge includes most of a utility's fixed costs), a RD rider and a straight fixed-variable rate design. Although other ratemaking methods might address the alleged problems of revenue insufficiency and utility disincentives for energy efficiency – a declining block rate structure and an earnings sharing

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[44] A state commission might have other objectives, but for this example it considers the four specified ones as the critical ones for decision-making.

mechanism, for example – the assumption is that the commission, for whatever reason, would not seriously consider them.[45]

The next step in the MCDA process would require the commission staff or some other objective party[46] to assess the performance of the candidate ratemaking options according to each criterion. This part of MCDA demands objective analysis and information compiled by commission staff. Judgment is necessary, but it is objective judgment. This aspect of the ratemaking process is more scientific in nature, as predicting the outcomes for the different ratemaking options relies on economic theory and empirical evidence on the experiences of the options in real-world applications. Let us assume that the analyst gives the following scores (from a scale of 1-5, with a higher score indicating better performance) to each option for each criterion:

Ratemaking Method/Objective	**Revenue sufficiency**	**Incentives for energy efficiency**	**Economic efficiency**	**Public acceptability**
Standard tariff	2	1	3	5
RD rider	5	3	3	3
SFV	5	3	5	1

For each criterion, the performance scores require at the minimum how each option compares with the others. We know that the utility is less likely under both the RD rider and SFV, for example, to experience a revenue shortfall than under the standard two-part tariff. For some readers, to say that each of these methods should receive a score of five while the standard method receives a score of two would seem hard to fathom. Yet, these scores could come from objective information and analysis. The commission staff, for example, could compute the average deviation of actual earnings from allowed earnings over the past several years, assuming each ratemaking mechanism was in place. Assigning scores to each option requires judgment by the analyst supported by objective information.[47]

45 The commission might eliminate outright these other ratemaking options because they impede critical regulatory objectives previously enunciated by the commission.

46 An objective party would advocate the public interest rather than special interests.

47 Even for the criterion "public acceptability," a commission could receive information from a survey of consumers or other focus groups to quantify the performance scores for each ratemaking option.

Next, the commissioners collectively (i.e., the decision-maker) must express their relative preference for each criterion by assigning relative weights to them. This activity is a commissioner-level activity because it requires balancing various elements of the public interest. Let us assume that commissioners assign the following weights (which add up to 100 percent):

- Revenue sufficiency: 30%
- Incentives for utility-initiated energy efficiency: 20%
- Economic efficiency: 10%
- Public acceptability: 40%

The weighting of each criterion by decision-makers (i.e., the commissioners) requires purely subjective judgment. The above illustration shows that the commissioners assign the most weight to how the public will react to any ratemaking method – a weight four times as heavy as the weight assigned to economic efficiency.[48] The hypothetical commissioners allot the next highest weight to revenue sufficiency. At the other extreme, they assign the lowest weight to economic efficiency. The commissioners consider revenue sufficiency to be three times more important in serving the public interest than economic efficiency, and one and a half times more important than incentives for utility-initiated energy efficiency.

The next step involves combining the performance scores and "criterion" weights to compare and rank the different options. One strategy or decision rule (the next subsection identifies other strategies) is to add up the scores for each option, weighted by the significance attached to each criterion, and rank the options based on the weighted scores. We can express this so-called additive linear (i.e., decision) rule as:

$$V_j = \sum w_i s_{ij},$$

where w_i represents the weight assigned to the ith criterion and s_{ij} is the score ascribed to the jth option for the ith weight. The overall value for each option (V_j) equals the performance score for each criterion (for example, the performance score of SFV for promoting economic efficiency, which in the illustration equals five, times the weight of that criterion), summed across all criteria. In other words, the overall score for each option is a weighted average performance metric, where the weights represent the relative importance of each criterion. The additive linear rule is appropriate only if the scores assigned to one criterion do not affect the scores assigned to other criteria (e.g., the performance score

[48] Commissions should not view public acceptability as something necessarily outside the control of the ratemaking process. How the public reacts to a particular ratemaking option would depend, for example, on efforts to educate customers on the justification for the option and on its content.

assigned to revenue sufficiency is independent of the score assigned to economic efficiency); that is, the criteria are mutually exclusive.

This aggregation rule involves simple arithmetic and has intuitive appeal as an indicator of the public interest. The total-score concept coincides with the utilitarian theory that options with the highest scores would have the most beneficial effect on the public interest. The additive linear rule provides a cardinal ranking of options, revealing both the order and the "outcome" distances between options. The weights reflect the trade-offs between different objectives. By pursuing the SFV option, for example, a commission impedes the "public acceptability" objective. Comparing and ranking the options based on total scores account for the importance of all criteria collectively. Under the rule, maximizing the weighted sum of the criteria leads to a desirable option.

Table 4 illustrates the construction of a performance matrix applying the weights and performance scores given above. The example shows that the RD rider has the highest total score with SFV rate design having the lowest score. The reason for the attractiveness of the RD rider, relative to the standard tariff option, is its better performance in advancing the objectives of revenue sufficiency and incentives for utility-initiated energy efficiency. The trade-off is that the commissioners deem the RD rider to have lower public acceptability. If commissioners choose the RD-rider option, implicitly they are willing to risk the possibility of public disapproval – and perhaps have planned to take measures to address the disapproval by explaining the long-term benefits of its decision -- to advance what they consider objectives that are more important.

Table 4: An Example of a Performance Matrix for Ratemaking Options

Ratemaking Option/Criterion	Revenue sufficiency w = 30%	Incentives for utility-initiated energy efficiency w = 20%	Economic efficiency w = 10%	Public acceptability w = 40%	Total score
Standard tariff	2 **.6**	1 **.2**	3 **.3**	5 **2**	**3.1**
RD rider	5 **1.5**	3 **.6**	3 **.3**	3 **1.2**	**3.6**
SFV	5 **1.5**	3 **.6**	5 **.5**	1 **.4**	**3.0**

Regarding the SFV option, in this example it ranks the lowest because of the combination of the high weight assigned to public acceptability and its low performance for this criterion. From the standpoint of economic efficiency, the SFV option outperforms the other options. Yet, this outcome contributes little to its total score because of the low weight assigned by the hypothetical commissioners to economic efficiency.[49] The preference of RD riders over SFV suggests that, with these two options neutralizing each other for the objectives of revenue sufficiency and incentives for utility-initiated energy efficiency, public acceptability dominates the economic-efficiency criterion. For convenience, our illustration simplifies the real world, where state commissions may frown upon SFV for other reasons. These reasons may include the adverse effect it would have on low usage customers and the fundamental change in rate design that it represents.[50]

In determining the robustness of the relative scores for the different ratemaking options, commissioners can vary the weights assigned to the criteria in addition to the performance scores for each option-criterion combination.[51] Let us first assume that commissioners view SFV as having the same public acceptability as the RD-rider option. In that scenario, SFV would have the highest score. (In Table 4, assigning a performance score of three to the SFV-public acceptability cell brings the total score for SFV to 3.8.) Assigning a higher weight to economic efficiency could also improve the score for SFV relative to the other options.

The previous illustration applying MCDA simplifies the complexities of real-world ratemaking decisions by state commissions. It shows, however, how this decision-making tool provides a conceptual framework for better understanding why commissions prefer some ratemaking options over others. If a commission seems to lean toward a particular option scoring poorly in all categories other than public acceptability, the commission would know that public acceptability implicitly dominates all others. The commission might then want to reevaluate this propensity, recognizing that it would jeopardize other objectives also deemed important (although lesser so).

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49 This explanation seems consistent with recent experiences where RD riders have met with more approval by state commissions than SFV has. At the time of this writing, state commissions across the country have approved a SFV rate design for five gas utilities and have approved a RD rider for seventeen utilities. Gas utilities in eleven states had RD riders pending before state commissions.

50 In other words, a commission may disfavor SFV because it violates a "fairness" standard and the "gradualism" objective.

51 The performance scores might not require sensitivity testing when based on objective analysis. Because of the uncertainties over some of the performance score, however, commissioners may find sensitivity testing useful.

For commissions, applying a systematic approach like MCDA can help make ratemaking decisions, and the underlying reasoning, more explicit, rational, efficient and transparent. It can assist commissions in making trade-offs among multiple objectives by allowing commissions to consider the implication of different value judgments on the relative importance of each objective (i.e., whether changing the weights for the objectives will change the ranking of options). Solving a multi-criteria problem, such as ratemaking, usually involves finding a solution by making trade-offs among the different objectives. Also from a utility perspective, knowing the trade-offs, values and rationale of a commission in using MCDA could help a utility to better understand and respond to commission policy from the outset. MCDA can achieve maximum success and benefit, therefore, than if the decision-making process is done in a vacuum.

Table 5 illustrates the major tasks for commissions in executing MCDA. These tasks coincide with the seven steps of MCDA identified earlier in this section. A commission might find it difficult to perform all of these tasks quantitatively. At the minimum, however, it can at least qualitatively undertake these tasks in its decision-making process. A commission can assess whether a particular rate design would hinder certain objectives while advancing others without knowing exactly the overall effect on the public interest.

Table 5: A Generic Multi-Criteria Approach for Evaluating Ratemaking Options

Step	Task
Framing the decision problem	• What is the nature and consequences of problems with the existing ratemaking mechanism? • How would the situation look under ideal conditions? • How would alternative ratemaking options address the problems? • In general terms, what effect would the ratemaking options have on individual regulatory objectives?
Defining the objectives and evaluation criteria	• Articulating ratemaking principles underlying "just and reasonable" prices • Identifying criteria of ratemaking consistent with those principles
Specifying the ratemaking options	• Identifying ratemaking options that can address current problems
Developing the performance matrix	• Collecting unbiased information • Analyzing each candidate ratemaking option for each specified criterion • Ranking or measuring the performance of each ratemaking option for each criterion
Identifying the preferences of the commissioners	• Ranking or weighting of criteria by commissioners
Selecting a strategy or decision rule	• Combining the information from the performance matrix with the commissioner's preferences for each criterion • Comparing each ratemaking option based on a decision rule (e.g., additive linear rule)
Interpreting the results and applying sensitivity analysis	• Evaluating each ratemaking option based on the decision rule • Identifying the stability of the relative rankings with varying criterion weights and performance assessments

3. Alternative strategies or decision rules

In using the generic MCDA approach, commissions can choose from several strategies in deciding on what ratemaking practice(s) to approve and reject. The previous discussion focused on one strategy, the additive linear rule, which considers all criteria, weights them and multiplies them by the performance scores for each option. The decision-maker then ranks the options based on total scores.

The MCDA literature identifies several other strategies, which require less information and are less demanding than the additive linear rule:

a. *Bounded rationality strategy*: The decision-maker finds an option acceptable even if not optimal; this strategy avoids having to assign quantitative weights to each criterion. The decision-maker uses the rule of thumb that an option is acceptable, at least for further consideration, when it meets or surpasses a threshold for the most important criteria. Assume that commissioners deemed equity and revenue sufficiency as the only critical criteria. As long as an option seems not to violate fairness standards[52] in addition to allowing the utility a reasonable opportunity to earn its authorized rate of return, commissioners can find the option acceptable if not the superior choice. Passing muster, for example, may mean that a ratemaking option achieves a minimum score (say 3 or 4) for the criteria equity and revenue sufficiency.

b. *Elimination-by-aspects strategy*: This strategy is similar to the bounded rationality strategy in eliminating those options that fail to satisfy critical criteria or do not have highly desirable attributes. It proceeds to set a threshold value for the most important criterion and then proceed to the next important criterion, and so forth. A commission could exclude, for example, any option that received a score of two or lower on "economic efficiency." One outcome of this strategy, as well as of the bounded rationality strategy, is that an option could outperform another option for most of the criteria but the decision-maker rejects it if it fails the most significant ones. This strategy becomes less problematic to the extent that the most important criteria overwhelm the other criteria (for which this strategy gives little consideration) in advancing the public interest. The commission might assign extremely low weights to these other criteria, thus assuming that they have little effect on the public interest.

c. *Incrementalism strategy*: This strategy compares the performance of new possible options with the option currently in place. The intent is to look for options that can best overcome the problems associated with the current option. The term "incrementalism" refers to the nature of this strategy to improve

[52] Undue discriminatory rates, and rates that shift all risks to consumers when the utility can better shoulder those risks and have some control over them, would seem to violate a fairness standard.

upon the status quo, rather than take a comprehensive review of all options in terms of their overall effect on the public interest. This strategy might limit a commission's review of ratemaking options, for example, to those that accommodate a utility facing competition and avoid the possibility of uneconomic bypass. The commission might confine its review to ratemaking options like special contracts, discounted tariffs or value of service prices. The commission might focus almost exclusively on the efficacy of a rate to allow the utility to compete on an equal basis with competitors. By ignoring other rate objectives, or giving them inadequate consideration, the commission risks approving a rate that, while promoting the objective at the center of attention, impedes other objectives that affect the public interest as well.

d. *Lexicographic strategy*: This strategy assigns a distinctly higher weight to certain criteria. It proceeds by ranking the options based on the most important criteria. If two options tie, the decision-maker then ranks them based on the second most important criterion, and so forth. If commissioners deem revenue sufficiency as the most important criterion, as an example, it could view the RD rider and SFV rate design options as equals. If commissioners identify incentives for utility-initiated energy efficiency as the second most important criterion, they may again consider the two options as equals. If then commissioners deem public acceptability as the third most important criterion, they might then decide to choose the RD rider over SFV.

e. *Conjunctive strategy*: This strategy requires that for any single option to warrant non-rejection it must meet a minimum threshold for each criterion. A decision-maker might reject outright a declining-block rate structure just because it violates the objective of encouraging price-driven energy efficiency. A seasonal rate structure might also not pass muster because of the large effect it could have on increasing utility bills during the period of peak usage.[53]

A commission can combine different strategies for selecting a ratemaking option. It can eliminate certain options, for example, using the bounded rationality strategy and then apply the additive linear rule to assess the surviving options. Taking our previous illustration, a commission might immediately eliminate the SFV option because of its low score for public acceptability, and

[53] Similar reasoning can explain the little use of real-time pricing for small electricity customers. Depending on the specific design, such pricing can result in highly volatile prices that a commission may deem would lead to widespread public opposition. Real-time pricing could also lead to customers having higher utility bills if they do not curtail their consumption during peak periods, again depending on the rate design. (See K. Costello, "An Observation on Real-Time Pricing: Why Practice Lags Theory," *The Electricity Journal*, vol. 17, no.1 (January-February 2004): 21-25.)

then select either the standard rate option or the RD rider option based on the additive linear rule.

A commission may also supplement any of these strategies by adapting them to new information. A commission can review a new ratemaking mechanism after a few years to determine whether it has performed as expected. This review involves both monitoring performance and revisiting the objectives, the performance scores under those objectives, and the weights for the objectives. As an illustration, assume that a commission previously approved a RD rider but circumstances have changed in three years where the gas usage per customer has ended its historical downward trend, and utility-initiated energy efficiency has becomes less important because of sharply falling gas prices. This scenario should cause a commission to pause and reconsider continuing with the RD rider.[54] By not reviewing periodically new ratemaking mechanisms or even longstanding ones for that matter, the risk is that the mechanism, although tenable when approved, might no longer serve the public interest.

Scores for performance range from one to five, with a higher score indicating better performance. The boldface score in each cell equals the performance score for the ratemaking option for a criterion times the weight of the criterion. The weighted score for the revenue-sufficiency performance of the standard ratemaking option, for example, equals 2 x 30% = .6.

V. Conclusions

The conflicting effect of different ratemaking practices on regulatory objectives exemplifies the complexity of commission decision-making in assessing the different practices. Commissions usually assign a set of objectives to ratemaking, each having a different effect on the public interest. When a commission considers different ratemaking options it also has to consider the trade-offs involved. In supporting marginal cost pricing, for example, a commission advances the goal of economic efficiency while possibly impeding the goals of gradualism and fairness. The observation that commissions infrequently endorse marginal cost pricing infers that they consider the downside effects of this pricing methodology to dominate any economic-efficiency benefits. Countless other examples exist where a commission has to contemplate the positive and negative outcomes of a rate proposal before reaching a decision.

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[54] Such a review assumes the RD rider had negative features (e.g., risk shifting to consumers) that the commission judged to fall short of the positive features, with the commission consequently approving the mechanism. Later, these positive features might no longer be relevant, thus calling into question the merits of the RD rider.

State commissions should take a rational and pro-active stance on ratemaking. State commissions often react to the filings of utilities and the positions of other stakeholders in the absence of predetermined principles and criteria for ratemaking. Under this strategy, the utility takes the first step in framing the issues in line with its interests, which may conflict with the public interest. As a preferred approach, a commission should take the initiative by laying out ratemaking principles and by identifying the objectives /criteria that a ratemaking proposal should follow. Ratemaking principles would tend to be invariant over time, as they should represent a general guide to good ratemaking under a wide array of market, technological and political conditions. Objectives/criteria, on the other hand, can change as markets evolve and the economic and political landscape changes. New ratemaking objectives can emerge, with some old ones discarded or relegated to a lower status. How commissions weigh these objectives can change over time and vary among utilities as they face different circumstances.

The MCDA approach presented in this paper can improve regulatory decisions by making more explicit the relationship between different ratemaking options and the public interest. (See Table 6 for a comparison of the current approach used by most state commissions for ratemaking with the MCDA approach.) It allows a commission to assess systematically proposals based on both unbiased and subjective information. Under this approach, prior to a utility proposal, a commission would have enunciated its ratemaking principles and objectives in a public proceeding. The MCDA approach helps commissions to (a) recognize the overriding goal of serving the public interest, (b) articulate their objectives and the relative importance of each, and (c) apply a decision rule or strategy that takes as input unbiased information and analysis as well as the ratemaking principles and objectives previously enunciated. Under one application of this approach, commissions specify and weight the objectives, analyze the effects of each ratemaking option on those objectives, and evaluate and rank each option in terms of satisfying the overall objectives (i.e., serving the public interest).

Table 6: Comparison of the Current Decision-Making Process for Ratemaking with the MCDA Approach

Current Approach	MCDA Approach
• The commission defines the public interest in terms of a list of principles and attributes underlying ratemaking (based on past decisions and other past actions taken by the commission) (no explicit or implicit weighing of objectives in advancing the public interest)	• In a separate public forum, the commission identifies the underlying objectives of ratemaking and the relative importance of each one (i.e., the commission constructs a "public interest" index that relates the public interest to weighting of the underlying objectives)
• A utility files ratemaking proposals rationalized on the basis of advancing those regulatory objectives skewed to its own interest	• A utility files ratemaking proposal addressing each underlying objectives identified by the commission (i.e., makes arguments for its rate proposal using commission guidelines)
• Other stakeholders, with their own interests, respond to utility proposal with criticisms and recommendations	• Other stakeholders respond to the utility proposal by addressing the objectives previously identified by the commission, either for opposing the utility proposal or for recommending an alternative ratemaking proposal, or both
• Commission staff advises commissioners on the proposals and recommendations of stakeholders	• Commission staff complies unbiased information and conducts an objective and comprehensive analysis of ratemaking proposals by stakeholders
• Commission staff sometimes proposes its own preferred ratemaking mechanism	• Commission staff makes recommendation taking into account both its analysis and previously enunciated commission guidelines
• Commissioners issue an order rationalizing their decision and its rejection of proposals, based partially on reaching a compromise of the different positions	• Commissioners issue an order rationalizing their decision based on consideration of all the objectives of ratemaking previously identified and the "public interest" index, in addition to the information provided by stakeholders and commission staff

Appendix

Descriptions of different ratemaking practices

Standard two-part tariff: The utility recovers non-gas costs from customers by charging them a fixed customer charge plus a volumetric or usage charge. The utility recovers most of its fixed costs (i.e., costs that do not vary with customer usage, at least in the short run) through a volumetric charge. The utility's ability to recover its authorized rate of return depends on the level of gas sales. With fixed costs recovered through a volumetric charge, customers receive inefficient price signals. The utility would have an incentive to promote gas sales, as additional sales would increase earnings since additional revenues would exceed incremental costs.

Revenue-decoupling (RD) rider: The utility adjusts its rates between rate cases for sales deviating from some baseline level. If a utility's actual sales per customer over a specific period fall below the level assumed in setting existing rates, the utility could increase its rates to compensate for the revenue shortfall. This mechanism helps to stabilize a utility's revenues and earnings. It shifts some business risk to customers, since a fall in sales would have no direct financial effect on a utility but it would increase rates. For this reason, the utility is indifferent to the level of sales, thereby removing any harm from energy efficiency either initiated by it or its customers.

Straight fixed-variable rate: The utility recovers all of its fixed costs (both customer and demand related) through a fixed monthly charge (e.g., customer charge) that is independent of customer usage. It recovers all of its variable costs (i.e., costs that vary with the quantity of service) through a volumetric charge. Similar to a RD rider, this rate design separates a utility's earnings from its actual sales. This rate structure provides customers with price signals conducive to efficient gas consumption. It also removes any utility disincentive to promote energy efficiency, since any revenue declines would equal avoided costs. Compared to the standard two-part tariff, this rate structure would increase the gas bills of low usage customers and decrease the bills of high usage customers; it would also tend to reduce winter gas bills and increase summer bills. Finally, compared to the standard two-part tariff, this rate structure reduces the benefits to consumers from using less gas.

Weather normalization adjustment: The utility adjusts its rates to account for sales deviating from some baseline level because of abnormal weather. Since usually a gas utility's marginal price is greater than avoided cost, sales fluctuations affect a utility's earnings; namely, reduce earnings when sales fall and increase it when sales increase. The major rationale for this mechanism is that weather is difficult to predict and weather conditions have a significant effect on both sales and utility earnings. A weather normalization adjustment helps to stabilize both a utility's earnings and customers' winter gas bills (e.g., with an extremely cold winter, rates would be adjusted downward to account for higher than normal-weather sales). On the downside, concerns may arise over the shifting of sales risk to customers and the public perception that the mechanism primarily serves to protect the utility from weather-related events, namely, warmer-than-normal winters.

Inverted-block rate: The customer pays an increased rate for gas consumed at successively higher blocks. As an illustration, the customer would pay $3.00 per thousand cubic feet (Mcf) for the 100 Mcf, and $5.00 for all consumption over 100 Mcf. This rate structure promotes energy conservation by discouraging customers from using larger quantities of gas. One form of this rate structure, referred to as a lifelines rate, has the purpose of keeping gas costs down for low-income customers, who presumably consume less gas than other customers. When the marginal cost of a utility does not increase with additional consumption, inverted rates reduce economic efficiency and result in price discrimination against high usage customers. Inverted rates may set the rate of the initial block below average cost (to provide lower prices for "essential" gas use and to better meet the needs of low-income customers), with the rate of the tail block above average cost to encourage conservation. Finally, a utility is at risk for not recovering its fixed costs through the tail blocks, which depends upon gas usage that is sensitive to weather and energy-conservation efforts.

Declining-block rate: The customer pays a lower rate for gas consumed at successively higher blocks. As an illustration, the customer would pay $5.50 per Mcf for the first 100 Mcf, and $4.50 for all consumption over 100 Mcf. This rate structure promotes the sale of gas by lowering the marginal price to larger customers from additional consumption. A utility's earnings become more stable when the recovery of fixed costs occurs in the low usage blocks, where customers will inevitably consume at the minimum. This rate structure promotes economic efficiency when the price at higher usage blocks, within which customers use gas, corresponds to variable or marginal cost. When marginal cost does not decline with higher levels of consumption, this rate structure is discriminatory in favoring larger users. Finally, by encouraging sales, this rate structure would tend to improve system utilization (i.e., the ratio of average demand to system capacity, defined over a specific time).

Cost rider: A utility adjusts its rates to recover certain costs without a formal rate review. These costs could include those that deviate from some baseline (e.g., bad-debt costs that exceed the level implicit in current rates determined by a commission in the last rate case). These costs can also include zero-based expenses. A commission might allow a utility to recover all the costs, for example, it incurred in promoting energy efficiency outside of a rate case review. One justification for a cost rider is the inadequacy of using historical cost to predict future costs. A rider has the intent of stabilizing a utility's earnings and reducing the likelihood of future rate cases. On the downside, a rider could cause a utility to have less incentive to control its cost with the diminution of regulatory lag. Another concern is that a rider would shift risks to consumers, since supposedly the utility could more easily pass through excessive costs, or any cost increase for that matter, to consumers.

Cost-based customer charge: Customer costs include those costs associated with serving customers, irrespective of the amount or rate of gas usage. These costs include operating and capital costs that vary directly with the number of customers. One issue in recent rate cases is whether a utility should raise the customer charge in line with customer costs. According to cost-of-service studies, most gas utilities have customer charges set below marginal customer costs. On grounds of economic efficiency, increasing the customer charge would improve economic efficiency, since the volumetric or usage charge would consequently better reflect a utility's variable or marginal cost. A higher customer charge would also tend to increase summer gas bills and reduce winter bills, as well as mitigate the effect of weather on customer bills. On the downside, a higher customer charge could harm low usage customers and meet with public disapproval, especially for increasing minimum summer gas bills.

Flexible rate: The utility is able to charge a price to certain customers within a specified range. A commission would designate a price ceiling and floor, within which a utility could charge. Short-run marginal cost might act as the price floor, and fully allocated cost (e.g., embedded accounting cost) as the price ceiling. This ratemaking practice is often the result of competitive market conditions compelling a utility to offer a rate to certain customers that fall below the standard or fully allocated cost rate. A flexible rate can help deter uneconomic bypass, where a customer switches to a competing fuel or gas provider when the economic cost of that provider is greater than the cost of local gas utility service. Flexible rates can result in value of service rates that account for the demand characteristics of customers. These rates are discriminatory in that the utility would charge different rates to customers in the same class (as long as they fall within the zone of allowable rates). Flexible rates raise the issue of who should bear the cost of discounts (i.e., revenue shortfalls from fully allocated cost revenues) – utility customers, utility shareholders, or both groups sharing the costs.

Special contract: The utility negotiates with a large business or industrial customer for a favorable rate and other terms and conditions. Usually the customer has service alternatives and faces unique circumstances that require a utility to offer the customer a special deal. The customer might otherwise leave the utility service area, not expand its business, or close its business. Special treatment to an individual customer constitutes a discriminatory action but one that, arguably, is justifiable under certain conditions.

Discriminatory rate in general: The utility charges two different prices for an identical service even though the costs are the same. More generally, discriminatory pricing occurs when price differences for the same service do not correspond to cost differences. Discriminatory pricing considers customers' willingness to pay, which depends on the ability of customers to find alternative suppliers or to engage in self-supply. A utility may establish a rate, for example, based on the opportunities of an industrial customer to switch to another fuel. A utility may have to offer a rate below fully allocated costs to a particular customer or group of customers to meet the demands of competitive forces. Discriminatory pricing may help a utility to reduce its surplus capacity and improve the utilization of existing capacity by offering a lower rate to customers who would respond by increasing their usage. Discriminatory pricing raises a question of fairness, especially when a favorable rate falls outside a zone of reasonableness. When a rate falls short of a utility's short-run marginal cost or lies above the price that an unregulated monopolist would charge, for example, a commission would likely find the rate impermissible.

Marginal cost rate: Favored by economists, rates that correspond to the change in total cost from a utility providing an additional unit of service (i.e., marginal cost) should give customers proper price signals. Marginal cost pricing takes a forward-looking perspective by accounting for prospective costs rather than historical costs. The rate can stimulate usage, especially when a utility has surplus capacity. Compared to the standard two-part tariff, marginal cost pricing would move the non-variable cost portion of the revenue requirement to a fixed charge. Its drawbacks include the difficulties in estimating marginal cost (e.g., long-run marginal cost) and the adjustment in rates needed to reconcile marginal-cost revenues with a utility's revenue requirement. The latter requirement might violate acceptable equity standards by charging higher rates to captive customers.

Seasonal rate: The utility charges higher rates during seasons of the year with high usage. The rationale for this price differential is that the utility incurs higher costs, both on the margin and on average, during periods of high demand. A gas utility may incur additional high-pressure distribution costs and storage costs during the winter months. The rate should result in more efficient use of gas system facilities and give customers better price signals. On the downside, a seasonal rate would cause higher winter gas bills, provoking public opposition and concerns over the aggravation of gas-service unaffordability, especially to low-income households.

Earnings sharing: The utility adjusts its rates periodically (e.g., annually) when its actual return on equity falls outside some specified band. If the band encompasses a 10-14 percent rate of return on equity, when the actual return is 9 percent, the utility could adjust its rates upward to increase its return to 10 percent. This mechanism helps to stabilize a utility's rate of return without a formal rate case review. Compared to traditional ratemaking, because of the diminution of regulatory lag this mechanism may reduce the incentive of a utility to control its costs between rate cases. On the upside, earnings sharing should reduce the frequency of future rate cases and allow adjusted rates to coincide closer to recent market developments, including those affecting a utility's costs.

Targeted subsidized rate: The utility offers a price discount to advance some social objective such as universal service and service affordability to low-income households. The rate offered to achieve these objectives might fall below short-run marginal cost, resulting in a burden on either utility shareholders or non-targeted customers, or both. A preferential rate directed at low-income households, for example, may involve a straight rate discount (e.g., a 20 percent discount from the cost-of-service rate) or a percentage-of-income payment plan (PIPP) where a utility bills an eligible customer based on a specified percentage of her household income.

APPENDIX - B

INFRASTRUCTURE NEEDS AND FUNDING ALTERNATIVES FOR ARIZONA: 2008-2032

WATER, ENERGY, COMMUNICATIONS AND TRANSPORTATION

ARIZONA INVESTMENT COUNCIL

Executive Summary

May 2008

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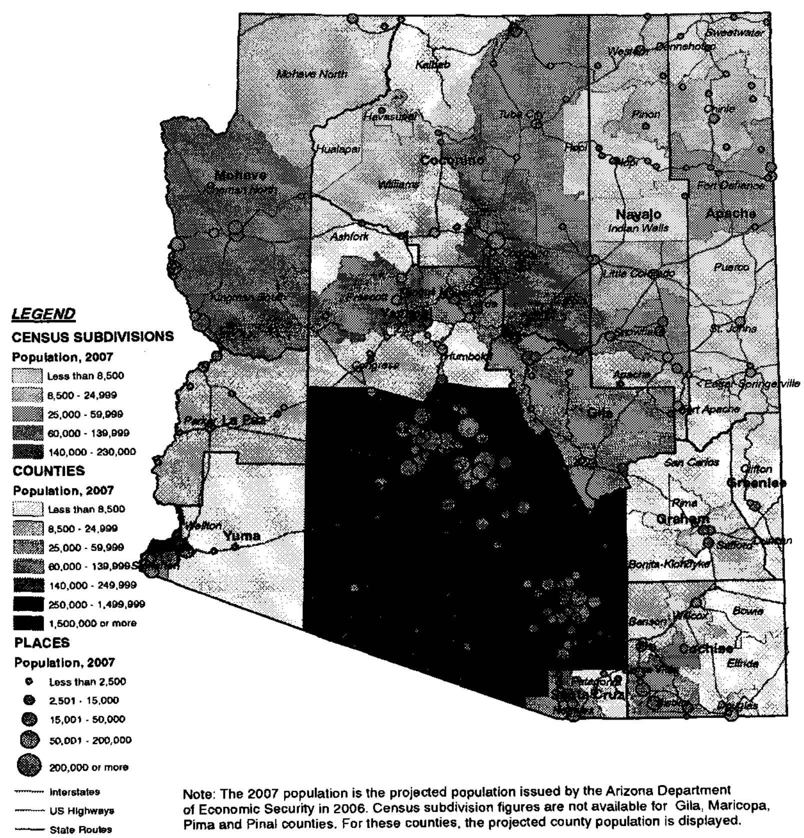
A Future of Growth in Arizona

Arizona has been among the Nation's leaders in population growth for decades. People continue to be attracted to the State for its climate, job opportunities, life style, and western spirit of independence. Between 1980 and 2007, the State's population rose by nearly 3.8 million (an increase of 137%).

Similarly, explosive population growth is in store for the State's next 25 years. Between 2008 and 2032, the projected change in population is even larger - at 4.2 million people (a 65% increase).

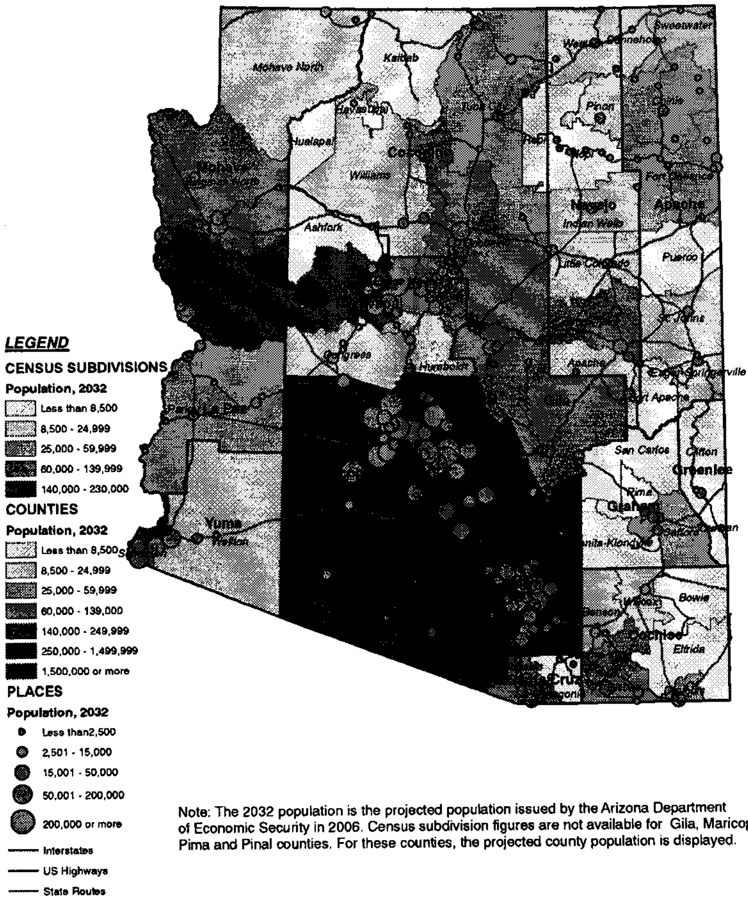
Neither the State's population growth nor its corresponding infrastructure needs will be evenly dispersed across the State. The map below highlights current population centers around the State, as of 2007. The map that follows highights expected growth patterns.

2007 Population of Census Subdivisions and Places in Arizona



Note: The 2007 population is the projected population issued by the Arizona Department of Economic Security in 2006. Census subdivision figures are not available for Gila, Maricopa, Pima and Pinal counties. For these counties, the projected county population is displayed.

2032 Population of Census Subdivisions and Places in Arizona



Note: The 2032 population is the projected population issued by the Arizona Department of Economic Security in 2006. Census subdivision figures are not available for Gila, Maricopa, Pima and Pinal counties. For these counties, the projected county population is displayed.

Population growth will continue to be concentrated in Central Arizona, in Maricopa, Pima, and, increasingly, Pinal counties. Maricopa County will see the largest numeric population increase with 2.5 million new residents (representing a 64% increase). While Pinal County's numeric increase is smaller, at 600,000, its percentage increase is the largest, at 207%. Pima County is forecast to gain 470,000 new residents (a 47% increase).

Growth's Opportunities

A growing population will allow the State to build its significance as an economic center in the Southwest. If Arizona takes the opportunity now to build cutting-edge telecommunication, energy, transportation, and water and wastewater infrastructure networks, the State will rival others in promoting economic growth and prosperity.

Growth gives Arizona the opportunity to:

- build cutting-edge telecommunications infrastructure that puts the State on par with world telecommunications leaders like Japan, Korea, and France;

- realize forward-thinking energy infrastructure that accounts for the new realities of the 21st century - like soaring oil and natural gas prices and an increasing desire to reduce our negative environmental impact;

- host growing populations well into the future by leading innovation on water conservation and supply augmentation solutions - as other states in the Southwest grow increasingly thirsty and competition over the region's limited water supplies intensifies;

- build an efficient and safe transportation infrastructure to carry the State's people and goods within, into, and out of the State.

Growth's Challenges

A growing population is forcing Arizonans to make tough decisions about planning for, and financing, needed infrastructure projects. The State's growth has already placed a heavy strain on existing public and private infrastructure. In the water and wastewater and transportation sectors, especially, significant investment is needed to replace and rehabilitate creaking infrastructure. Arizona's projected *future* growth will place even greater pressure on the State's infrastructure.

At this critical juncture, the State must decide if it is indeed willing to embrace the kind of growth forecast in this study. An unwillingness to confront the challenges posed by Arizona's forecast growth will not only limit the opportunity to become one of the region's leading economic centers, but may end up stifling growth itself.

Accommodating growth fully is going to be very, very costly. We estimate the cost of infrastructure in the transportation, telecommunications, water and wastewater and energy sectors ranges between $417 billion and $532 billion for the next 25 years.

ENERGY

Arizona faces important and difficult decisions about how to meet rapidly growing demands for energy.

Over the next 25 years, electricity demand from the growing population will increase by about 85 percent.

Demand for natural gas will nearly double over the forecast period, as will demand for petroleum products, requiring a 33 percent increase in product fuel delivery capacity and storage.

Overall, in the energy sector (including electricity, natural gas, petroleum and other fuels) the total capital investment in energy infrastructure required to serve Arizona's growing population to 2032 is between $74 billion and $86.5 billion depending upon the mix of generation technologies employed going forward.

Current funding for electricity in Arizona is insufficient. The total funding gap for the energy sector, without any change in the current funding regime, is likely to be around $109 Billion.

The time to act is now. With construction lead times of eight years or more, now is the time to plan for new facilities and to think of new ways to finance infrastructure in a capital intensive sector.

Business as Usual?

In the last 10 years alone, electricity demand has increased about 41 percent. The state managed through this period of rapid growth by building a large number of gas-fired plants—enough to quadruple gas-fired capacity in the state.

Yet there are a number of reasons to believe that business as usual - a relative reliance on natural gas-fired plants - may not be the best strategy for meeting the challenge of future growth. For one, natural gas has become much more expensive since the 1990s, when relatively low natural gas prices drove a surge in natural gas plant construction. Given expected fuel market conditions, gas-fired generation may no longer be the low-cost method of producing electricity.

Secondly, as environmental concerns escalate and a collective willingness to take action to reduce carbon emissions emerges, both natural gas and coal generation methods are likely to be discouraged (without major technological breakthroughs, at least).

If coal or nuclear generation methods are to be preferred to gas - for either financial, economic or environmental reasons - the decision must be made within the next few years if the plants are going to be ready to meet the needs of Arizonans a decade from now.

The Bottom Line

Overall, in the electricity and natural gas, petroleum and other fuels sectors, the total capital investment in energy infrastructure required to serve Arizona's growing population to 2032 is likely to be between $74 billion and $86.5 billion.

Energy Infrastructure Costs, 2008-2032

The cost of new energy infrastructure has been rising rapidly in recent years and is likely to continue to do so over the next few decades. Inflation in materials and construction activity has been pushing up relative costs in all capital-intensive industries, including energy. And electricity generation is likely to become even more capital intensive than it is now. Consider that:

- capital costs per MW are much higher for coal and nuclear than they are for gas;
- a new renewables mandate has recently taken effect, and the cost per MW of solar and wind generation is especially high.

Forecast Total Energy Infrastructure Costs, 2008-2032 (Millions)

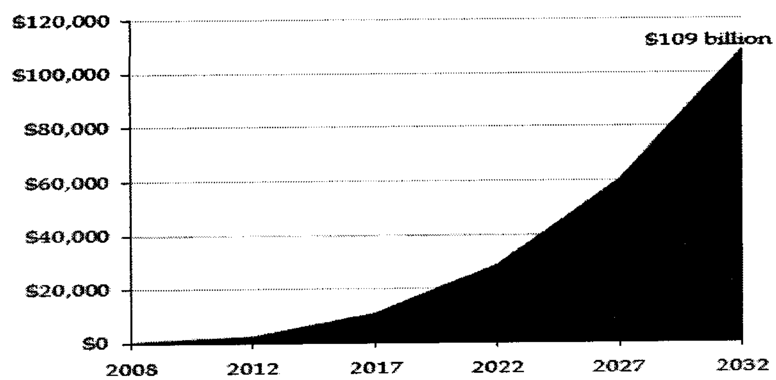
	Electricity	*Natural Gas, Petroleum, and Other Fuels*
Total Capital Costs	**$65,000-$77,400**	**$8,980-9,080**
Generation:		
Coal Scenario	$44,900	N/A
Gas Scenario	$36,100	N/A
Nuclear Scenario	$48,500	N/A
Refineries	N/A	$3,600
Transmission	$9,600	$2,780
Distribution	$19,300	$2,400
Storage	N/A	$200-300

Paying for Energy Infrastructure: Challenges Ahead

In the natural gas, petroleum, and other fuels sector, there is no immediately obvious funding gap for pipeline or storage provision. Demand will be met by the private sector, which has historically demonstrated an ability to quickly meet demand with supply. However, there is an obvious disconnect if power generators and gas distributors are not able to fully recover their costs sufficiently to enter into long-term supply contracts with pipeline operators.

In the electricity sector, the picture looks quite different. Assuming that the price of electricity is fixed at its 2006[1] level, there will be a cumulative funding gap over the entire forecast period of $109 billion.[2]

Cumulative Funding Gap in the Electricity Sector



[1] 2006 electricity rates (for all sectors) are the latest available from the EIA's profile of Arizona.
[2] The funding gap includes costs associated with operations and maintenance as well as fuel costs.

Any of the funding mechanisms currently used to generate infrastructure funds for energy projects in Arizona could be modified to bridge the gap between funding under current mechanisms and costs in the next 25 years. For example, usage fees, hook-up fees or transmission fees could be increased.

Arizona's ability to bridge the $109 billion funding gap may be more limited. Arizona is in the precarious position of having major utilities with poor bond ratings and, at the same time, a sluggish regulatory process that results in periodic (typically large) rate changes rather than smooth rate ones. When market investors doubt the ability of a utility to recover costs in a timely fashion, ratepayers must absorb higher interest costs for the utility's debt financing.

The optimal portfolio of infrastructure investment is one that makes sense financially and environmentally. To make smart choices, the power industry and its stakeholders must develop more innovative ways of ensuring that necessary infrastructure is adequately funded. These might include:

- changes in the determination of usage fees – for example, establishing a process that allows for more frequent but smaller rate increases to minimize the effects of regulatory lag and reduce the impact of rate shock on Arizona businesses and consumers;
- establishment of specific capital recovery mechanisms to facilitate more timely recovery of required distribution, transmission and generation investment – to the extent that generation is provided by the market (via independent power producers), such a mechanism should be geared toward ensuring that utilities are of sufficient financial health to enter into long-term purchase contracts;
- the creation of a transmission infrastructure authority – to provide power providers with access to low cost loans in order to finance the construction of transmission infrastructure and/or generation;
- any other method that smooths out the pattern of expected price increases, improves the timeliness and predictability of capital investment recovery, and balances the costs of growth with who pays for growth.

A New Era of Electricity Prices

Driven by declining fuel prices, falling long-term interest rates and one-time benefits of over investment in generation, electricity prices have fallen substantially since the early 1980s, on an inflation-adjusted basis.

But the era of declining electricity prices is over; retail prices will have to rise to allow producers to recover the higher cost of fuels and more expensive methods of generation that are necessary if the industry is to support environmental initiatives. Specifically, the price of electricity will have to rise at or above the rate of inflation over the next 25 years in order to compensate producers and distributors for the full costs of meeting Arizona's electricity demand.[3]

[3] It is important to note here that changes in usage fees for the majority of providers in Arizona are large determined by the Arizona Corporation Commission. Therefore, as changes in usage fees require regulatory approval this affects the efficiency of usage fees being able to adjust to eliminate any funding gap.

TELECOMMUNICATIONS

In Arizona and the United States generally the thirst for access to high-speed data, voice, and video services is rapidly increasing among residential and commercial users. The system is increasingly failing to keep pace with the demands put upon it by Arizona's connected users.

Yet a significant minority of the State's population does not even have access to basic broadband internet.

To provide broadband connectivity to the currently un-served population of Arizona would cost between $1-2.2 billion.

Creation of a state-of-the-art statewide fiber to the home (FTTH) network would costs an *additional* $23 billion that would give Arizonans the same speed of access as the citizens of countries such as Japan, France and Korea.

The Motivation for Improving Telecommunications

Access to a high quality telecommunication infrastructure is vitally important for the economy in Arizona and its residents' quality of life.

Businesses increasingly rely on access to telecommunications infrastructure - particularly, access to high-speed data lines - to complete their business activities. Examples abound: from the lettuce farmer in Yuma who supplies Subway to the trauma specialist available to offer remote help to physicians in smaller hospitals across the state.

Serving Arizona's Unserved Population

Access to broadband connections is already widespread in Arizona, particularly in urbanized areas.

However, approximately 3 percent of Arizonans lack access to necessary "middle mile"[4] broadband connectivity. These "middle mile"-constrained communities are home to approximately 200,000 Arizonans.

We estimate the extension of "middle mile" lines to un-served areas of Arizona so that residents and businesses in those areas have access to broadband services would $1-2.2 billion for the 25 year period to 2032.

Providing the 'Gold Standard'

The world is becoming increasingly connected and markets more competitive due to increasing access to high-quality telecommunications.

[4] Middle mile fiber connects communities to the long haul (cross-country) fiber.

Not having a state-of-the-art telecommunications infrastructure is detractor for businesses and residents when deciding if they should locate in Arizona.

Put another way, a "gold standard" telecommunications infrastructure (which most commentators observe to be fiber to the home) would *attract* new businesses and more highly-skilled jobs to the state.

We estimate the provision of fiber to the home (FTTH) - the "gold standard" level of service - to all households in Arizona would cost approximately an *additional* $23billion.

The Bottom Line

Costs to Connect Households, 2008-2032 (Millions)

	"Middle Mile" Connectivity[5]	Fiber-to-the-Home[6]
Capital Costs	$744-1,613	$9,087
Ongoing Costs	$258-548	$14,001
Total	**$1,002-2,161**	**$23,088**

Ensuring Access

The un-served areas of Arizona are those communities that are small in population with low population densities and/or are a significant distance away from any telecommunication infrastructure. Private sector providers have been reluctant to make substantial investments in remote areas where subscriber density is low and the cost of providing service is high.

The costs of investing in universal FTTH are also currently commercially prohibitive. We may well need the public and private sectors to act in concert to ensure our social and business well-being.

The State might well try one or a combination of the following to enhance the State's infrastructure:

- anchor tenancy - the State and local governments purchase all their bandwidth needs from a single concern and in return the company provides infrastructure to areas that otherwise would not receive service.
- public-sector provision of infrastructure - municipalities build, operate and maintain their own telecommunications infrastructure.
- creation of a telecommunication infrastructure bank - this provides municipalities and private companies access to low cost loans in order to finance telecommunication infrastructure.

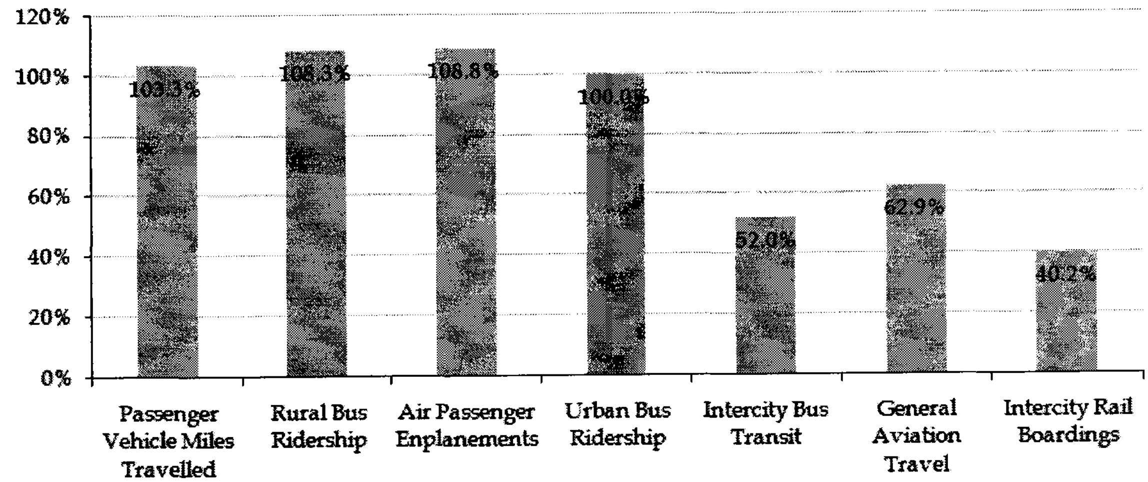
[5] Costs vary depending on whether the telecommunication line is deployed aerially (typically less expensive) or is buried (more expensive).
[6] These costs are in *addition* to the "middle mile" connectivity costs that must also be spent to provide FTTH.

- establishment of a *broadband* universal service fund - allows telecommunication providers access to a source of funds they can utilize when providing broadband services to above normal cost of provision communities.
- reduction of right-of-way (ROW) costs - streamlining or limiting ROW costs reduces the overall burden on telecommunications providers.
- alteration of building codes - require new buildings or re-models to be wired to provide fiber to the home.
- re-alignment of tax incentives - level the playing field for telecommunications so that it receives the same tax treatment as other sectors on its infrastructure investments
- offering grants to the private sector for areas that are not commercially viable without support.

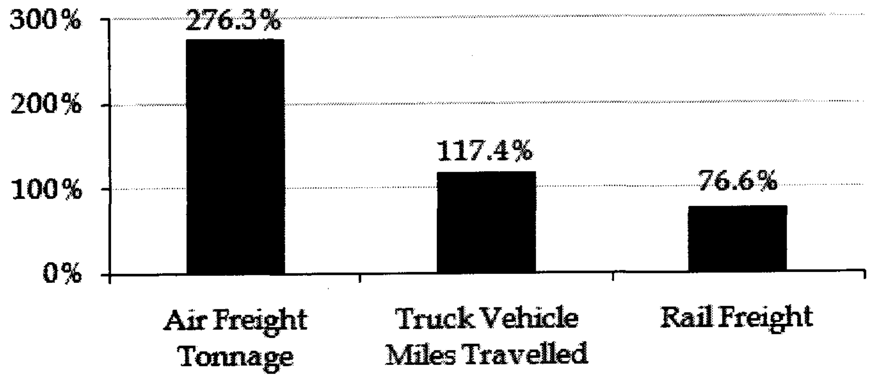
TRANSPORTATION

Transportation demand is set to increase dramatically over the next 25 years as Arizona's population grows. The following two figures illustrate.

Forecast Passenger Transportation Demand Increases, 2008-2032



Forecast Freight Transportation Demand Increases, 2008-2032



Passenger road usage is set to more than double. Truck freight tonnages will also more than double. Air freight tonnages will almost treble.

Meeting Arizona's Growing Transportation Demands

The State, as well as its counties and cities currently have (limited) plans to improve transportation infrastructure in the coming years. Yet even with these planned improvements in place, burgeoning demand will cause performance levels to *decrease* on the State's roads, railways, and in the airports.

Without significant infrastructure investment, the percent of road passenger travel at an acceptable level of service will fall from 77 percent statewide in 2002 to 38 percent in 2025. Average delay per trip statewide will increase nearly six-fold over the same period.

The Infrastructure Bill: What Enhancements Will Cost

The bill for improving Arizona's transportation network so that the roadways and highways, transit system, airways, and railways meet the rapidly growing demand for them is huge. The total capital bill over our 25-year study period is approximately $253-311 billion.[7] Roadways and highways make up the largest share of that bill - 79-83 percent - though paying for infrastructure improvements in the other sectors will be critical, too.

[7] Though it could well top $561 Billion if road construction inflation of 8.6% of the recent past continues over the 25 years.

Estimated Costs of Arizona's Needed Transportation Infrastructure Projects, 2008-2032

	25-Year Capital Costs (Billions)
Roadways and Highways	**$198.8[8]-$257[9]**
Transit	**$35.8**
Railways	**$5.9**
Airways	**$12.1**

The $253-311 billion cost estimates include costs to complete the transportation infrastructure improvements that are already in the works as well as those projects that will be necessary to maintain system performance at an acceptable level to 2032.

One factor that could potentially drive these costs even higher is the rising cost of construction. Over the last two decades, construction cost inflation has averaged 4 percent - well above consumer price inflation. In the last five years, though, construction costs have risen an average of *8.6 percent* each year.

Paying for Transportation Infrastructure

There is a huge gap between the money that current funding mechanisms can generate and this $253-311 billion infrastructure bill. The Arizona Department of Transportation estimates that within seven years Arizona will be in a "preservation only" mode,[10] meaning that incoming revenues will be sufficient only to support operations and maintenance costs; there will be no money available to fund new capital projects from current mechanisms.[11]

Assuming current funding mechanisms fund only operations and maintenance costs, then, the State is heading toward a funding chasm.

Some of the major current funding mechanisms include:

- the Highway User Revenue Fund (HURF) - which includes the State gasoline tax, and the Vehicle license tax (VLT) amongst other things;
- the Maricopa County Transportation Excise Tax- which includes the Regional Area Road Fund and the Public Transport: Public Transportation Fund (PTF);
- Federal funds from the Safe, Accountable, Flexible, Efficient Transportation Equity Act: a Legacy for Users (SAFETEA -LU) bill;
- the Highway Expansion and Extension Loan Program (HELP) - the "State Infrastructure Bank (SIB)"- allows agencies to begin construction of highways before funding is received;
- tax credits;
- the Airport Improvement Program (AIP)- which is administered by ADOT;
- the aviation Passenger Facility Charge (PFC)- a fee that is applied to every enplanement.

[8] Using 2.2 percent inflation.
[9] Using road construction inflation of 4% - its level of the last 15 years.
[10] For all regions that have not voted to collect additional transportation taxes.
[11] http://www.azdot.gov/Index_Docs/Headlines/index.asp

These are a mixture of usage fees, taxes, federal funding and indirect taxation that are used for transportation infrastructure and services. There may be some possibility for the extension and manipulation of these to squeeze out a little more money for enhancements but this is probably somewhat limited.

There are a number of alternative funding mechanisms that could be used to bridge the cost/funding gap, including:

- local options to levy fuel taxes - allow municipalities to set their own gas tax rates;
- additional regional sales taxes - increase the sales tax at the regional or State level;
- regional or State impact fees – when new developments are build impose an impact fee to support transportation projects;
- public private partnerships (P3s) - have the private sector build, maintain and operate transportation infrastructure;
- charges based on roadway use- these would include congestion pricing, mileage-based fees, and/or toll facilities.

Whichever funding method, or combination of funding methods, is chosen, the bottom line is clear: the costs for securing adequate transportation infrastructure to serve the Arizona's increasing passenger and freight transportation demands, which will clearly grow dramatically in the next 25 years, are unprecedented and certainly far greater than the costs Arizonans have become accustomed to.

WATER AND WASTEWATER

The era of "cheap water" in Arizona has passed: water delivery and wastewater services are going to have to become much more expensive.

Arizona needs to spend in excess of $109 billion over the next 25 years on its water and wastewater infrastructure. Current funding sources will fall some $30 billion short of what is necessary.

The requirement for and ability to fund infrastructure needs varies quite dramatically across the State. In Cochise, Coconino, Gila, and Yavapai counties the funding gap will be much larger comparatively, and the communities' ability to overcome that gap much more limited.

Challenges in the Water and Wastewater Sectors

Arizona is at a crossroads. The infrastructure built several decades ago – principally the SRP and CAP systems – will not meet the demands of a rapidly growing population. Significant new capital investments – in Central Arizona and in other parts of the state – are required to provide a sustainable water supply to future populations.

In addition, the water delivery and treatment systems built decades ago are now due for replacement – what the American Water Works Association calls the "dawn of the replacement era" is upon us in Arizona.[12] Furthermore, easy supply augmentation options are no longer available.

As we look to water reclamation and even desalination to augment our existing water supplies, outlays for capital and O&M will increase. Climate change will also have unknown, though potentially adverse, effects on Arizona's water resources.

Planning for future populations is critical. In some cases effective planning involves securing new water supplies - which can be legally, institutionally, and financially very complex. In other cases it involves large-scale capital projects, which take time to finance and build.

Meeting Arizonans' Water and Wastewater Needs to 2032

The water and wastewater infrastructure built several decades ago in Arizona will not meet the demands of a rapidly growing population. Significant infrastructure investments will be required in the next 25 years to:

- rehabilitate and replace aging drinking water delivery and wastewater treatment systems;
- build new drinking water delivery and wastewater treatment systems to support future populations; and
- augment existing water supplies in counties with current or impending water supply/demand gaps to provide sustainable sources of water for future populations.

The total infrastructure bill, including capital outlays, operations and maintenance, and debt service costs, to meet the water and wastewater needs of current and future Arizonans over the next 25 years is just over $109 billion.

[12]American Water Works Association, *Dawn of the Replacement Era: Reinvesting in Drinking Water Infrastructure*, May 2001, <http://www.win-water.org/reports/infrastructure.pdf>.

Estimated Total Water and Wastewater Costs, 2008-2032 (Nominal Millions)

	Water	Wastewater
Total Capital Costs	**$30,716**	**$14,162**[13]
Drinking Water Infrastructure[14]	$29,121	
Coconino County Supply Augmentation[15]	$652	
Cochise County Supply Augmentation	$217	
Yavapai County Supply Augmentation	$197	
Gila County Supply Augmentation	$31	
Dam Renovation and Replacement	$336	
SRP Well Rehabilitation and Replacement	$161	
Total Ongoing Costs	**$42,088**	**$22,139**
Total: All Costs	**$72,804**	**$36,301**

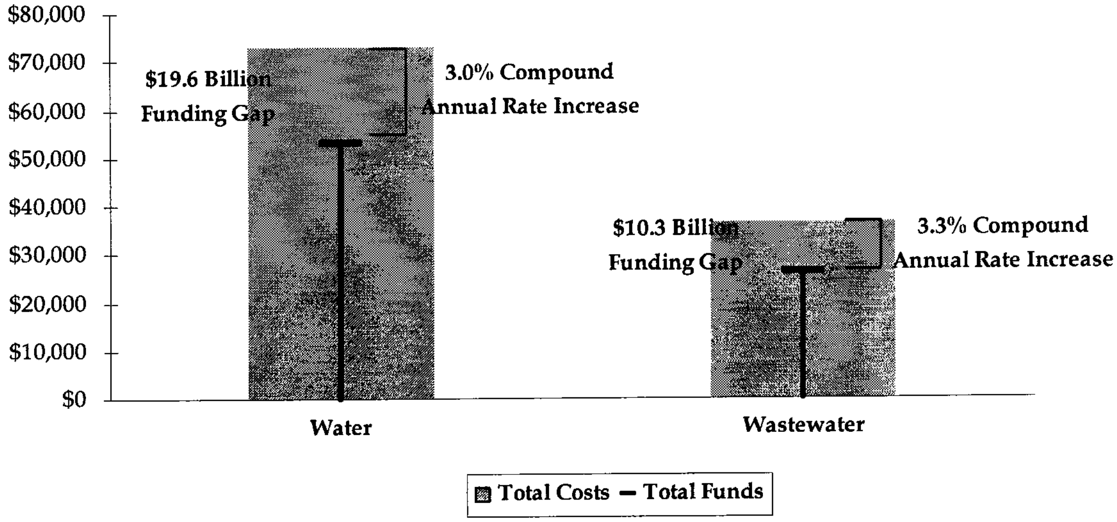
The Bottom Line: Paying for Water and Wastewater Infrastructure

Examining current funding mechanisms through our 25-year study period, monies available to cover capital outlays, operations and maintenance, and debt service total $79.3 billion - approximately 73 percent of the total $109.1 billion infrastructure bill. That makes for a total 25-year funding gap of approximately $30 billion.

If user fees alone were used to close the funding gap, the required one-time price increase is about 55 percent in the water sector and 62 percent in the wastewater sector. These one-time increases translate to annual rate increases of 3.0 percent and 3.3 percent, respectively, across the entire 25-year period.

[13] Wastewater capital costs include the rehabilitation and replacement of wastewater and stormwater systems to serve existing populations as well as the construction of new systems to serve future populations.
[14] Drinking water infrastructure costs include the rehabilitation and replacement of drinking water systems to serve existing populations as well as the construction of new systems to serve future populations.
[15] Supply augmentation includes projects to provide sustainable sources of water for future populations.

Water and Wastewater Funding Gap and Required Rate Increase



In addition to increasing usage fees, other mechanisms for bridging the funding gap might include:

- increasing providers' ability to issue bonds - the advantage of financing capital projects via bonding is that it enables providers to distribute the costs of a capital project over the useful life of the project;
- increasing capital contributions - increasing development/impact fees or requiring developers to secure larger amounts of infrastructure to be handed over to the public sector.

Per Capita Infrastructure Costs and Geographic Disparities

We've estimated a funding gap across the entire state. Yet the requirement for and ability to fund infrastructure needs varies quite dramatically across the State. In the areas with impending supply augmentation needs (Cochise, Coconino, Gila, and Yavapai counties) funding gap will be much larger, and the communities' ability to overcome that gap more limited. The table below highlights the per-capita costs of the supply augmentation projects that will be necessary to support existing and future populations in the counties with supply/demand gaps in the next 25 years.

Per Capita Supply Augmentation Costs by County

	Total Supply Augmentation Capital Costs	Per Capita Costs
Coconino County	$652 million	$4,752
Cochise County	$217 million	$1,547
Yavapai County	$197 million	$817
Gila County	$31 million	$543

While infrastructure costs in Arizona's other counties are not as dramatic as in the four counties noted above, they are not insignificant. On average across the state, the total annual per capita bill for water and wastewater infrastructure (capital and ongoing costs) - not including the costs borne by residents of the four counties (noted above) - is about $465.

It's important to remember, too, that our analysis ends in 2032. The water supply surplus in Central Arizona (including Maricopa, Pima, and Pinal counties) shrinks dramatically between 2008 and 2032. Water managers will be tasked with securing additional water supplies for Central Arizona well before 2050. And there's no reason to believe that supply augmentation options for Central Arizona will be any less expensive than the options we've discussed for Coconino, Cochise, Yavapai, and Gila counties.

APPENDIX - C

Special Comment

June 2006

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Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings

Summary Opinion

- With natural gas prices expected to remain at high levels, local gas distribution companies (LDCs) face earnings and cash flow pressures as their customers increase conservation efforts. In addition, bad debt expense has increased as more customers face increasing difficulties in paying their bills. Furthermore, LDC volumes remain subject to weather conditions.
- Moody's analyzed its gas LDCs (local distribution companies) and notes that weather normalized winter gas consumption in per customer usage has declined at an increased pace since 2003. This decline coincides with a period of steadily rising natural gas prices for the LDCs and steadily falling heating degree days.
- Had gross margins (gas revenues less cost of gas and associated gas taxes) been fully protected against gas consumption declines on account of customer conservation during the past five winters, they would have been higher by an average of $5.2 million in 2004 and $4.6 million in 2005. One company would have increased its profits by $18.3 and $11.6 million in those two years (3% and 2% of gas margins, respectively).
- Bad debt expense has shown a steady average increase in each of the past four winters, tracking the increase in natural gas prices during the same period.
- Despite the general increase in working capital and natural gas prices, LDC short-term debt has remained relatively flat from 2003-2005.
- Except for a handful of jurisdictions that employ full revenue decoupling (RD) through a mechanism akin to "balancing accounts" (California, Maryland and North Carolina), most companies prefer to keep the weather normalization clause (WNC) rate design separate from the conservation margin tracker.
- While some jurisdictions permit the application for RD to be requested outside the procedural norms of a full rate case, most would prefer a full rate case or rate review.
- LDCs pursuing a full or partial RD feel that it is an important aspect of their rate design requirements and most companies indicated that they would continue filing for it until their regulators gave final approval.
- Moody's observes that in the face of volatile natural gas prices, volatile weather patterns and other exogenous forces that would prompt gas customers to curtail gas consumption volumes from their utilities, LDC earnings and credit metrics will come under pressure.
- LDCs that have, or soon expect to have, RD stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in face of adversity. This difference between those companies that have RD and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident.

Introduction

At this time last year, Moody's published its first study dedicated to the question of gas conservation and its impact on gas LDC earnings and credit ratings (see Moody's June 2005 Special Comment titled *Impact of Conservation on Gas Margins and Financial Stability in The Gas LDC Sector)*. We found that while many companies were aware of the conservation factor and 18 of the 34 gas LDCs followed by Moody's could quantify the loss in their per customer volume consumption, only a handful of companies had taken the step to incorporate it into their rate design so that their gross margins would be unaffected. Last year we also discussed how three companies were approaching this rate design feature through slightly different decoupling mechanisms. While the approach may be different, the concept and end result are not. Companies in the gas utility business are increasingly interested in not only protecting themselves against gross margin variations caused by customer conservation (partial decoupling), but also by weather variations (full decoupling).

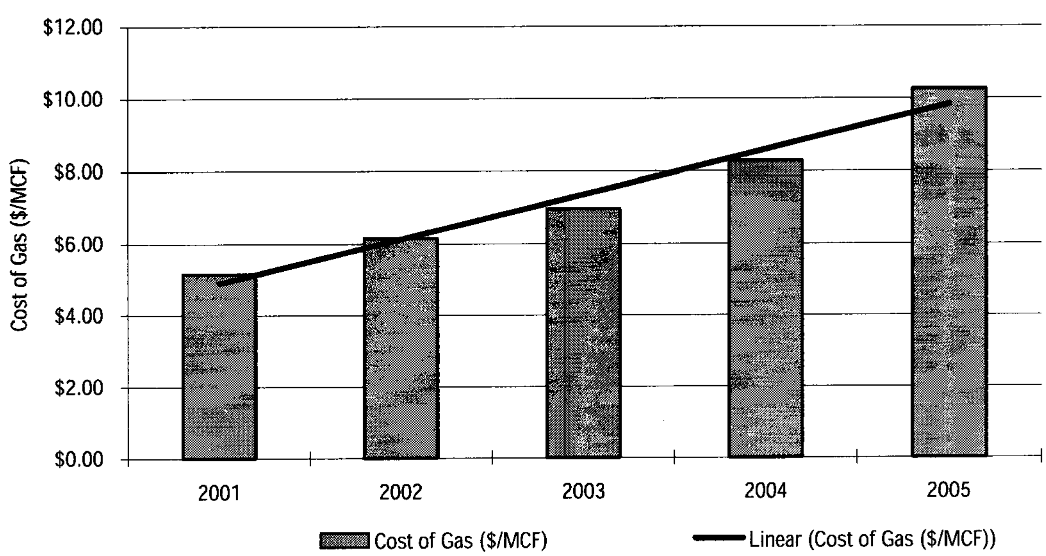
In keeping with the evolving convention, we will refer to these mechanisms as revenue decoupling (RD) in general terms and to "partial decoupling" to mean rate design protection for conservation or "full decoupling" to mean rate design protection for both conservation and weather variations. When a company only has weather normalization clause protection, we refer to the rate design as WNC. Fewer companies have conservation rate design protection without also having WNC as permanent features of their ratemaking.

As with our previous study, we define "conservation" as any technical advancement that improves home heating or gas appliance efficiencies as well as the curtailment of consumption on account of high gas commodity prices. Twenty three of the 34 gas LDCs followed by Moody's responded to various questions posed by Moody's and their results have been tabulated and presented in this paper in aggregate form in order to protect the confidentiality of information submitted.

Nationwide Trend of Rising Gas Prices and Falling Heating Degree Days

Companies overall responded that they were experiencing rising natural gas prices during the past five winter heating seasons, with their average gas purchase prices depicted in the graph below and labeled Increase in Cost of Gas (Fig.1). Natural gas prices rose by a compounded average growth rate of 17% during this period, with the sharpest rise occurring in the winter of 2005 (most recent winter heating season) where it registered an average price increase of 24% over 2004. The highest price recorded by an LDC during this past winter was $13.31/mcf and lowest $6.73/mcf with $10.70 being the median. While only half the respondents provided natural gas price estimates for 2006, those that did resulted in an average price of $10.71/mcf with $13.87/mcf being the highest, $8.61/mcf being the lowest and $10.59/mcf being the median. Most LDCs expect future natural gas prices to moderate, but the trend is still in an upwards direction and this has been found to be the prime driver for the conservation factor on the part of customers.

Figure 1
Increase in Cost of Gas to LDCs

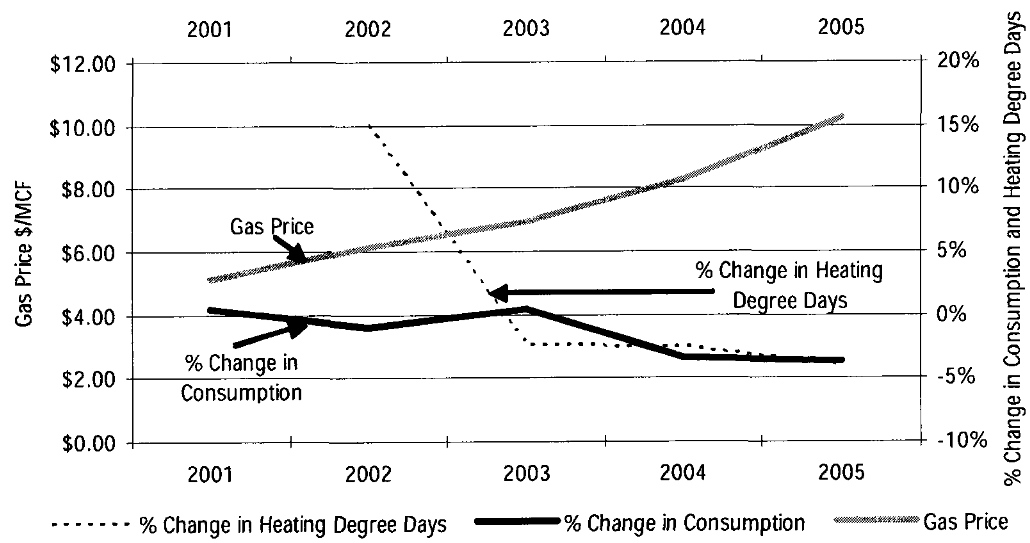


The other noticeable trend is that of falling heating degree days since the winter of 2002 among the responding LDCs. On average, the winter of 2002 appears to have been a fairly cold winter, but the number of heating degree days has since fallen by an average of 3-5% in each of the winter heating seasons since that year. LDCs lacking a WNC or full decoupling mechanism would have suffered in their gas consumption and gross margins when faced with the strong combination of warmer than normal winters and declining gas consumption on account of customer conservation.

Finally, except for a period in 2003 when the average customer consumption increased by .5%, the per customer consumption for residential and commercial users has fallen by 3-4% in each of the last two winter heating seasons on a weather normalized basis, representing that portion of loss in gas consumption resulting from conservation. Changes in gas prices are plotted against percentage changes in per customer consumption and heating degree days in Fig. 2. We note that while the change in per customer consumption on account of conservation has been declining since the 2003 winter heating season at a rate of 3-4% p.a., gas prices have continued to rise much more rapidly.

Figure 2

Gas Price vs. % Change in Consumption and Heating Degree Days



The winter of 2005 saw the most dramatic rise in both natural gas prices and also per customer gas consumption decline on account of conservation (4% average decline). The weather normalized consumption decline for the last winter ranges from 9.1% in the case of one LDC to a gain of 3.1% in another, as it had colder winter weather in 2005 compared with 2004. With the exception of another LDC that had no loss in consumption, all the other respondents had declines in gas consumption. Similarly, except for one LDC which experienced an increase in per customer consumption in 2004 of 1.2%, all others saw declines in per customer consumption from 2003 which ranged from -0.2% to -9.6%.

Impact of Conservation on Losses in Gross Margin

When LDCs were asked how much higher would their gross margins (gas revenues less cost of gas purchased and associated gas taxes) have been had they been fully protected against declines in gas consumption resulting from conservation, all indicated higher gross margins for the last two winter heating seasons. The average gross margins would have increased from a low of $2.4 million in 2003 to a high of $5.2 million in 2004, with one company indicating that they would have gained $18.3 million in 2004 alone and $11.6 million in 2005, where the average company stood to gain an additional $4.6 million in gross margin.

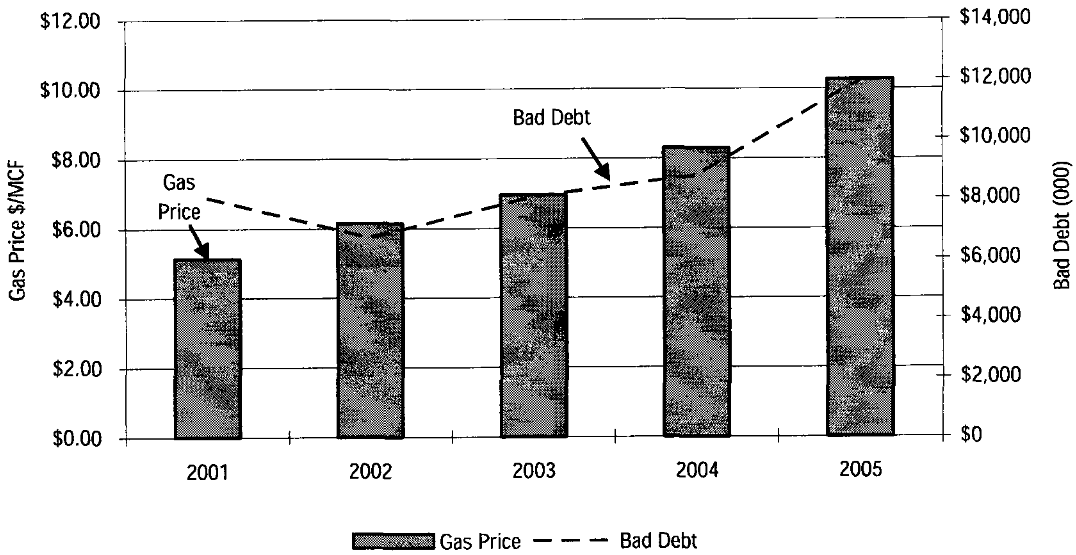
The problem of declining gross margins on account of per customer conservation is explained by the various rate filings and testimonies being offered by consultants on the subject. Symptomatic of the LDC conservation problem is the argument for incorporating a conservation protection design. For example, Questar Gas Company believes that earning its authorized return has been very difficult due to the combination of declining average consumption over time, the use of a historical test year in general rate cases, and the fact that most of its fixed-non-fuel costs are recovered through a volumetric charge. The upshot has been revenues that in normal weather years have fallen short of their own non-gas costs---because average-customer sales in the rate-effective years fell short of the (historical) test-year figures that were used to set rates. Questar would like to decouple its non-gas revenues from year-to-year movements in the per-customer average consumption levels. The mechanics of the decoupling would employ a balancing account to recover non-gas related revenues lost/gained when average consumption drops/rises above the projected average.[1]

In attempting to grapple with the conservation issue, LDCs are in fact, having to dispel the notion that their fixed charges should be recovered from volumetric sales of gas. As the fixed charges appear year in and year out regardless of gas usage, the volumetric approach to cost recovery for operating a gas distribution system is a faulty equation which needs to be rectified in ratemaking. It would appear therefore, that unless and until this anomaly is corrected, the LDC would lack the necessary tools with which to earn its allowed rate of return.

Bad Debt Expense and Increases in Working Capital

One consequence of rising natural gas prices purchased by LDCs and passed onto their customers is the higher level of bad debt expense and increases in working capital that these companies must now contend with. In the winter of 2005 for example, one LDC reported a doubling of their bad debt expense which increased by an average of 17% for all respondents. LDCs in some states such as those located in North Carolina, had the good fortune of being able to recover the gas component of bad debt expense through their purchase gas adjustment (PGA) mechanism, thereby reducing the level of bad debt expense that the company had to absorb on their own. Fig. 3 depicts the close correlation between rising average bad debt expenses and rising gas prices.

Figure 3
Gas Price vs. Bad Debt

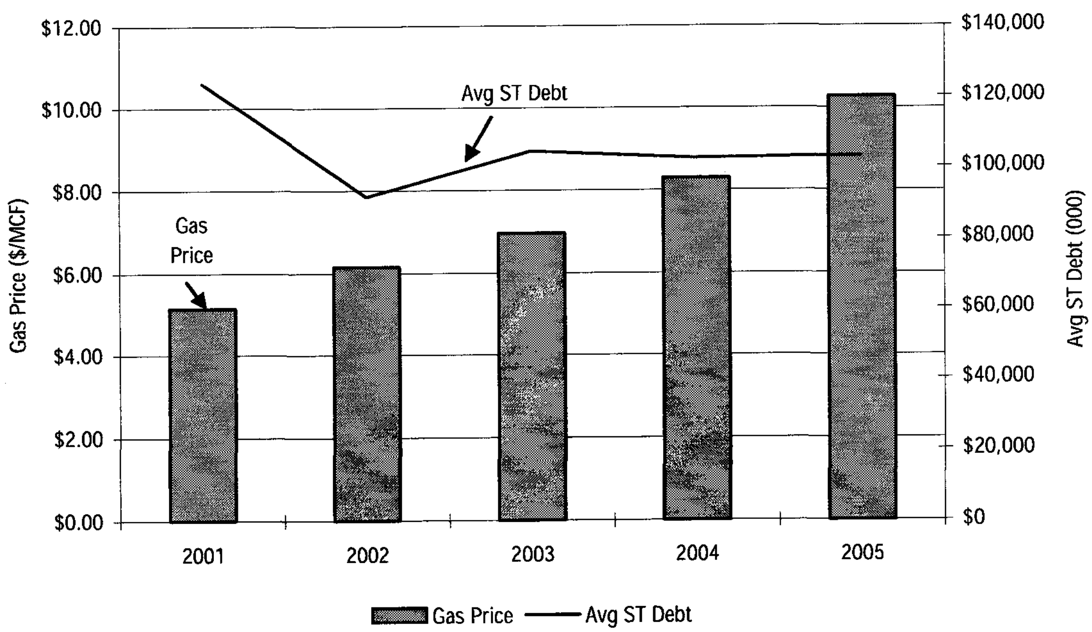


1. *Prefiled Direct Testimony of George R. Compton, Ph.D., for the Division of Public Utilities of the Utah Department of Commerce, Before the Public Service Commission of Utah, January 23, 2006, Docket No. 05-057-T01*

As one would expect, with the higher level of gas commodity prices that customers had to pay and the rise in bad debt expense experienced during the past three winter heating seasons, most LDCs incurred higher levels of working capital. The winter of 2005 witnessed one of the sharpest increases in seasonal working capital on account of accounts receivables and inventory build-ups related to higher natural gas prices, rising 136% over 2004 levels among those LDCs responding to affirmative increases in working capital levels. One large LDC reported a 185% increase in their 2005 working capital level over the prior year. Some companies however, were able to match their increases in accounts receivables and inventory with accounts payable by structuring their gas purchase transactions to more closely match their gas payments for inventory and timing these closer to the anticipated cash receipts from customers, so that they had less working capital to finance.

It is also interesting to note, as depicted in Fig. 4, that on average, LDC short term debt remained relatively flat after 2003 despite the continuing rise in the cost of natural gas prices. Some companies indicated that they were deliberately refinancing short-term debt through medium term notes or through other means of long-term debt by locking in the cost of financing under favorable interest rates, while others were able to contain the increases in their 2005 working capital levels and did not need to borrow as much for their seasonal needs. In fact, approximately half the LDCs indicating having higher levels of working capital in 2005 compared with prior years were able to reduce their short-term debt levels by refinancing via long-term debt or issuance of new equity.

Figure 4
Gas Price Vs. Avg Short Term Debt Outstanding



LDCs Take Varied Approaches in Integrating WNC with RD

It appears that LDCs that already have full RD similar to the "balancing accounts" including revenue normalization adjustments or customer utilization trackers being employed in certain jurisdictions such as California, Maryland and North Carolina, prefer to keep their rate designs intact as they are easily administered and allow for full recovery of their authorized margins. Most other companies that currently have WNC in some of their jurisdictions however, prefer to keep the conservation margin tracker or tariff separate, for the reason that their current WNC provide real time cash flow and earnings adjustments whereas the conservation trackers typically provide after-the-fact cash flow adjustments through deferral accounts that are collected over a subsequent 12-month period.

While some public utility commissions would permit the filing of RD outside the procedural norm of a full rate case, most would clearly prefer a full rate case to be filed in connection with a rate design alteration or at least to review a general rate case after-the-fact in short order. It also appears that the great majority of respondents experiencing customer gas consumption declines on account of conservation would be inclined to file and re-file for some form of RD if denied the first time by their regulators. For many, this is a long but necessary trek to take as a means of curing a rate design deficiency that appears to be increasingly untenable.

Conclusion

In our comment last year, we mentioned several LDCs that had the ability to correct for margin losses on account of conservation or weather variables through their rate design mechanisms, or had RD filing plans or extension plans. Among these, Alabama Gas Corporation (Alagasco) advises that their "rate stabilization and equalization" mechanism will continue through at least 2008 and Southern California Gas Company (SoCal Gas) appears to be satisfied with how their "balancing accounts" have been implemented previously and have requested that the regulatory commission continue with them going forward. Following the completion of an independent study to measure the effectiveness of its conservation mechanism, Northwest Natural Gas Company was able to obtain approval of the Oregon Public Utility Commission in 2005 to continue its conservation tariff for an additional four years through September 30, 2009, and increase the mechanism's coverage from a partial decoupling of 90% of residential and commercial gas usage to a full decoupling of 100%. It also maintains a separate weather normalization mechanism that was extended through September 2008.

In April of 2006, Cascade Natural Gas Corporation in Washington State obtained approval from the Oregon Public Utility Commission to implement a decoupling mechanism to track changes in margin due to conservation (variations in weather-normalized usage) and to track changes in margin due to weather variations from normal for residential and commercial customers. Cascade's RD application for Washington State is still pending.

Piedmont Natural Gas in North Carolina obtained approval for a full RD mechanism for a three-year trial period, with the state's Attorney General appealing the decision in the courts. The appeal has been initiated and the court has taken no action. In the meantime, the company has implemented the mechanism effective November 1 of 2005.

Washington Gas Light Company obtained a full RD (Revenue Normalization Adjustment) in its Maryland jurisdiction which went into effect on October 1, 2005. It has previously attempted to introduce at least partial RD in its Virginia and Washington D.C. jurisdictions.

Southwest Gas Corporation did not fare as well in its Arizona RD application where it generates 54% of its gross margin. The company's credit metrics were already weaker than its Baa utility peers and it badly needed an effective RD mechanism across all its jurisdictions to protect its gross margins. While the Arizona Corporation Commission finally granted it a partial rate increase after over one-year in the application process and brought current recent cost and customer usage factors in Arizona, it denied the company its request for RD through "balancing accounts" as it has in California. The company also lacks RD in its Nevada jurisdiction (37% of gross margins) and the company lost gross margins in 2005 when it experienced one of the 10 warmest years on record, which followed a warm 2003, one of the warmest years in over 100 years. The cumulative effects of this warmer than normal weather continued into the company's quarter ending March 31, 2006 which was mostly responsible for the company's loss of $9 million in operating margin. Moody's took action in May 2006 to downgrade the company's senior unsecured debt to Baa3 from Baa2 where it is currently under stable outlook.

In the meantime, the list of LDCs applying for RD continues to expand with Atmos Energy Corporation attempting to add conservation riders in key jurisdictions where it already has WNC, Indiana Gas Company and Southern Indiana Gas and Electric Company (utility subsidiaries of Vectren Utility Holdings) both applying for conservation margin protection in Indiana to supplement their recently approved WNC, and Questar Gas Corporation seeking a conservation tariff in Utah. New Jersey Natural Gas and South Jersey Gas Company filed for a joint RD application in New Jersey, requesting a full decoupling mechanism. Both of these New Jersey utilities already have WNC.

Moody's believes that the LDCs successful in their RD initiatives will stand a better chance than others in protecting their gross margins and overall credit metrics from the negative impacts of increasing volatility of natural gas prices and climatic changes. Stronger margins and earnings would also serve to cushion the blows inflicted by increases in bad debt expense that tend to accompany rising gas prices. As gas customers step up their conservation efforts in response to these rising commodity prices, it will become increasingly important for LDCs to switch from a gas volumetric cost recovery methodology to one of RD. While RD may have originally begun as a regional concept in certain jurisdictions, it has quickly become a nationwide phenomenon that will challenge regulators and gas utilities alike, as they seek to correct a structural imbalance in their rate design that has become increasingly difficult to ignore.

Related Research

Special Comments:

Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector, June 2005 (92798)

Comparative ROE Attributes of US Local Gas Distribution Companies, July 2004 (87301)

Negative Rating Trend for Local Gas Distribution Companies: Impact of Diversifications and Warm Weather, October 2002 (76344)

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